Columbia Gas of Kentucky
A NiSource Company

August 2, 2013

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602

RECEIVED
AUG 02 2013
PUBLIC SERVICE COMMISSION

Re: Columbia Gas of Kentucky, Inc.
PSC Case No. 2013-00167

Dear Mr. Derouen,

Enclosed for docketing with the Commission are an original and eight (8) copies of Columbia Gas of Kentucky, Inc.'s responses to Commission Staff's Second Request for Information. Should you have any questions about this filing, please contact me at 614-460-5558. Thank you.

Very truly yours,

Brooke E. Leslie
Senior Counsel

Enclosures

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2013-00167

CERTIFICATION OF RESPONSES TO INFORMATION REQUESTS

This is to certify that I have supervised the preparation of Columbia Gas of Kentucky, Inc.'s August 2, 2013 responses to the Commission Staff's Second Set of Information Requests and that the responses are true and accurate to the best of my knowledge, information and belief formed after reasonable inquiry.

Date: Aug. 2, 2013

Brooke E. Leslie

Brooke E. Leslie
Senior Counsel
Columbia Gas of Kentucky, Inc.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

1. Refer to Volume 1 of Columbia's application at Tab 22. In Columbia's capital construction budget, the amounts budgeted for 2013 and 2014 are $24.6 and $27.1 million, respectively, while the amounts budgeted for 2015 and 2016 are approximately $19.8 million each year. Explain why the projects in the budget have been scheduled in such a way that the greater amounts are in the two years that will be reflected in the forecasted test period.

Response: Columbia's capital program includes projects that are based on external requests. Capital expenditures on growth related projects are based on when customers express an interest in receiving natural gas and becoming customers. Capital expenditures on public improvement projects involve the relocation of facilities at the request of the local or state authorities due roadway reconstruction activity. Capital expenditures in these budget classes are not subject to Columbia's overall ability to schedule over multiple years and are contributing factors of the capital forecasts that Columbia submitted.

Columbia received an incremental $2 million this year from capital funding that was made available to the NiSource Gas Distribution business unit to continue towards effectively executing on its infrastructure program. In 2014, Columbia will spend $7 million to efficiently install AMR devices which will be completed within the calendar year.

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2. Refer to Volume 1 of Columbia's application at Tab 43. Explain why the forecasted industrial class transportation volumes in 2014 are more than 6 million cubic feet (roughly 4.0 percent) less than in each of the years 2013, 2015, and 2016.

Response:

The main driver of this volumetric difference is planned work by a single large industrial customer on its process equipment, causing related downtime in 2014.

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3. Refer to Volume 7 of the application at Tab 58, pages 5-6. The charts on these pages show the amounts charged to Columbia by NiSource Corporate Services Company ("NiSource Services") for the calendar years 2009 through 2012 and the amounts included in the proposed base and forecasted periods.

a.The annual amount charged Columbia during the historical period went from $11,142,715 in 2009, to $13,449,161 in 2012, an increase of $2.3 million, nearly 20.7 percent, or 6.9 percent annually. Explain in detail why the annual amount charged Columbia by NiSource Services increased by this magnitude over this period.

b. The annual amount charged is projected to increase by $1,707,724 from $13,449,161 to $15,056,885 from calendar year 2012 to the forecasted test period ending December 31, 2014, or 6.35 percent annually. Explain in detail why an increase of this magnitude is projected.

Response:

a. The types of functions performed by NCSC have not changed since 2009. However, since 2009, the work performed within certain functions has changed, often to address increased compliance activities or work requirements. The primary examples are as follows:

- Finance & Accounting – Staffing requirements within the Finance and Accounting group have increased primarily due to the need to implement the Finance Transformation project to meet compliance and reporting requirements. Staff was added to the Financial Planning and Analysis ("FP&A") group to improve the development of budgets, financial plans and budgetary controls in order to analyze operating costs and improve financial reporting. Finance & Accounting increased by approximately $138K primarily due to labor related to the aforementioned FP&A staffing,

- NiSource Gas Distribution ("NGD") Operations – The NGD segment transferred several operations-support functions to NCSC in order to leverage NCSC's intercompany billing system and service agreements, which has the capability to effectively distribute costs of shared services that need to be allocated across affiliates. NGD increased primarily due to the following:

- The increased transfers are in large part due to the additional capital program
    - There has been a significant increase in Corporate Services transfers due to the growing capital programs as additional FTE's are headed to support the program.
    - Between 2009 and 2012 there was some of the NiSource some shifting of employees from operating companies to NCSC to gain economies of scale. Of particular note was the safety functions. Employee Safety and Compliance responsibilities shifted from Columbia Gas of Kentucky to NCSC and is a primary driver of the costs increase. CKY has benefited from this centralized training and safety staff that increases both field and office safety and standardizes work practices across NGD.
    - The same shift from NGD companies to NCSC resulted in a consolidation of meter testing and repair of approximately $.2M

- During the 2009 to 2012 period, NGD converted GIS maps from paper to digital to increase efficiency by reducing facility location expense, lowering facility damages, and increasing accuracy of company records.
- Volume driven departments such as Call Center, Revenue Recovery (Collections), and Billing have increased due to an effort to improve the customer experience across the Columbia footprint; therefore, additional headcount has been added to improve customer interaction and better respond to their needs.

- Administrative Services – Staffing levels for IT Services have increased as a result of transitioning real-time systems ("RTS") support in-house. In addition, staffing levels increased as a result of the creation of the Project Management Office to assure control and oversight of capital investments. Administrative Services increased primarily due to increased staffing levels for IT Services, software and hardware maintenance and depreciation related expenses.

b. The primary reasons for the increase of $1,607,724 in the gross management fee between the periods are as follows: (1) Labor - $712,316 increase due to increased headcount and wage increases; (2) Employee Expenses - $253,415 increase related primarily to increased headcount; (3) Outsourcing Costs - $193,354 increase related to the NiSource Gas Distribution Customer Operations function which includes the Customer Call Center; (4) Legal Services - $139,737 increase due to anticipated increased activity over historic levels; (5) Maintenance Fees and Services - $118,835 increase related to software maintenance; and (6) Depreciation - $116,238 increase related to hardware.

Partially offsetting the $1.6 million increase in the gross management fee is an increase in management fee transfers to the balance sheet of $575,375 between periods. This increase primarily reflects growth in NCSC functions providing services that are capital in nature.

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4. Refer to Volume 7 of the application at Tab 59. Provide an electronic copy of all schedules under this tab with the formulas intact and unprotected and all rows and columns accessible.

Response:

This information is **CONFIDENTIAL**. The following computer files will be made available to parties who have executed a Non-Disclosure and Use Restriction Agreement: "COLUMBIA COS Model-2013-Design Day.xls", "COLUMBIA COS Model-2013-PeakAvg.xls", and "COLUMBIA COS Datasheet.xlsx."

COLUMBIA GAS OF KENTUCKY, INC.
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5. Refer to Volume 7 of the application at Tab 59, Schedule 2.

a. Refer to pages 1-13 of 144. These pages show allocations to the following rate categories: GS-Res, GS-Other, IUS, DS-ML/SC, and DS/IS. Provide a listing of Columbia's individual rate classes that are included in each category.

b. Refer to pages 14-25 of 144. Explain whether Columbia engages in natural gas production. If the response is no, explain why there are line items allocated to the Production function.

c. Refer to page 20 of 144 and Schedule 4, page 5 of 16. Accounts 920-926 on page 20 of 144 are functionalized using the allocation factor LABOR. Schedule 4, page 5 of 16, provides the allocation percentage as 100 percent to Distribution. Explain in detail how this allocation factor was calculated, including the accounts or line items included in the calculation.

d. Refer to page 38 of 144. Provide the rationale for allocating Miscellaneous Intangible Plant, Account 303, on the basis of the OUST allocation factor.

e. Refer to pages 39 and 45 of 144. Explain why Structures and Improvements, Account 375, is allocated using the DISTPT allocation factor on page

39, but depreciation expense on Distribution Land Structures and Improvements is allocated using the DEMAND allocation factor on page 45.

f. Refer to page 43 of 144 and Schedule 4, page 6 of 16. Operation Supervision and Engineering is allocated using the DISTLABOR allocation factor on page 43 of 144. Schedule 4, page 6 of 16 provides the allocation percentages as 19.65 percent to Demand, .2 percent to Commodity and 80.15 percent to Customer. Explain in detail how the DISTLABOR allocation percentages were calculated, including the accounts or line items included in the calculation.

g. Refer to page 45 of 144 and Schedule 4, page 6 of 16. Several accounts on page 45 of 144 are allocated based on the DISTL/P allocation factor. Schedule 4, page 6 of 16 provides the allocation percentages as 20.01 percent to Demand, .18 percent to Commodity and 79.80 percent to Customer. Explain in detail how the DISTL/P allocation percentages were calculated, including the accounts or line items included in the calculation.

h. Refer to page 122 of 144. Provide the rationale for allocating Land-LNG Plant using the DesignDayxMDS allocation factor.

Response:

a. See Table 1 below.

Table 1

Rate Category	Individual Rate Classes
GS-Res	GRS, G1R, IN3, IN4, LG2, LG3, LG4, GTR
GS-Other	GSO, G1C, IN3, LG2, GTO
IUS	IUS
DS-ML/SC	DS3, FX2, FX5, FX7, GDS, SAS
DS/IS	IS, DS, FX1, SC3

b. Columbia no longer engages in natural gas production. The amount of $7,678.39 in Account 30410 Land on the accounting records is related to production facilities once owned in Lexington and retired in 2000. At the time, the land was not removed from the accounting records because Columbia retained the rights-of-way for existing assets. This item was investigated in April 2013 and it was determined that the land had been donated to Community Housing. The amount was retired from the accounting records in May 2013.

c. Labor-related expenses were allocated based on the allocation of each particular FERC account associated with the labor expenses. Detailed calculations of the LABOR allocation factor are shown in the cost of service study computer models provided in Columbia's response to AG data request number1-4. Please see rows 525-572 of the "Functions" tab of the "COLUMBIA COS Model-2013-Design Day.xls" and "COLUMBIA COS Model-2013-PeakAvg.xls" files. Labor account line items are also shown in "COLUMBIA COS Datasheet.xlsx" on the worksheet under the "Labor" tab.

d. Over 98% of the plant balance in Account No. 303 consists of computer software. This computer software is classified as customer-related and allocated using a customer allocation factor consistent with its cost classification.

e. Depreciation expense associated with Distribution Land Structures and Improvements should have been allocated using an allocation factor that reflected the basis upon which all other Distribution Plant (excluding Land and Land Rights) was allocated to the rate classes.

f. The DISTLABOR allocation factor was calculated based on the labor portion of Account Nos. 870-920 and follows the cost classification of those accounts. Detailed calculations of the DISTLABOR allocation factor is shown in the cost of service study computer models provided in Columbia's response to Staff data request number 2-4. Please see rows 525-572 in columns Y-AA under the "Classify" tab of the files entitled, "COLUMBIA COS Model-2013-Design Day.xls" and "COLUMBIA COS Model-2013-PeakAvg.xls."

g. The DISTL/P allocation factor was calculated based on the classification of labor-related Administrative & General (A&G) Expenses in Account Nos. 920, 921, 922, 923, and 926, and plant-related A&G in Account Nos. 924, 925, and 935. Detailed calculations of the DISTL/P allocation factor are shown in the cost of service study computer models provided in Columbia's response to Staff data request number 2-4. Please see rows 282 and 290 in columns Y-AA under the

"Classify" tab of the files entitled, "COLUMBIA COS Model-2013-Design Day.xls" and "COLUMBIA COS Model-2013-PeakAvg.xls."

h. Columbia's LNG plant is used to increase the deliverability of gas volumes on its distribution system during peak day operating conditions. Therefore, allocation of the cost of land associated with the LNG plant was based on the maximum estimated volume of gas delivered to non-mainline customers on Columbia's design day.

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6. Refer to Volume 8 of the application, Tab C, Schedule C-2.1A, sheet 2 of 2, and Schedule C-2.1B, sheet 2 of 2.

a. The forecasted period expense for Account 904, Uncollectible Accounts, is $1,116,983, compared with the base period expense of $731,066. Explain why the amount is more than 50 percent greater in the forecasted period.

b. The forecasted period expense for Account 908, Customer Assistance Expenses, is $286,703, compared with the base period expense of $998,732. Explain why the expense amount is so much less in the forecasted period.

c. The forecasted period expense for Account 926, Employee Pensions and Benefits, is $2,188,889, compared with the base period expense of $3,197,725. Explain why the expense amount is so much less in the forecasted period.

Response:

a. The increase in Account 904 between the base period and forecasted test period is due to a projected increase in net charge-offs. Net charge-offs in calendar year 2012, a portion of which is included in the base period, were abnormally low. Please note that the forecasted test period amount is further adjusted on Schedule D-2.4.

b. The decrease in Account 908 between the base period and forecasted test period is due to the fact that tracker expense related to the Energy Efficiency/Conservation Program rider is not budgeted. The actual portion of the base period includes expense as recorded. There is no operating income impact as the financial plan and subsequent actual expenses ensure matching of tracker revenue and expense.

c. The decrease in Account 926 between the base period and forecasted test period is due to two items: (1) pension expense is decreasing by $763,540 primarily as the result of a higher level of pension settlement costs in the base period as compared to the forecasted test period, and (2) the ASC 712 post-employment benefits annual liability adjustment which is included in the actual portion of the base period but which has not been historically included in Columbia's forecasts due to the fact that it can vary greatly year to year, and the end of the ASC 712 transition obligation amortization during the base period.

**COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013**

7. Refer to Volume 8 of the application, Tab D, Schedule D-2.1, sheet 1 of 2. At the bottom of the page, the description of the ($10,379,987) adjustment to Other Gas Revenue indicates the adjustment is "to reflect the change in Other Gas Revenue and also to eliminate unbilled revenue recorded during the base period."

a. Explain the nature of the change to Other Gas Revenue and provide the amount of the adjustment specifically related to this change.

b. Provide the amount of the adjustment specifically related to the elimination of unbilled revenue recorded in the base period and explain what makes up the $368,597 amount included in the forecasted period.

Response:

Other Gas Revenue for the base period includes $4,674,002 of unbilled tariff revenue, $5,701,218 of off system sales revenue and $373,364 of miscellaneous revenue. The adjustment of ($10,379,987) removes all of the unbilled tariff revenue and off system sales revenue along with ($4,767) of miscellaneous revenue from the forecasted test year. The adjustment of ($4,767) accounts for the difference in miscellaneous revenue between the base and forecasted periods.

The $368,597 of miscellaneous revenue in the forecasted test period reflects a normalized six year average of the following revenue categories:

- Choice marketer billing and rate fees
- Customer billing services
- Gas lost, other accidental line breaks
- Gas transportation service banking penalties
- Other

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8. Refer to Volume 8 of the application, Tab D, Schedule d-2.2, sheet 2 of 3. Adjustment 9 indicates that the NiSource Services management fee is expected to increase by $381,275 from the base period to the forecasted period, an increase of 3.1 percent ($12,352,361 to $12,733,636). Explain why the management fee is estimated by NiSource Services to increase by this amount.

Response:

The primary reasons for the increase of $381,275 in the net management fee between periods are as follows: (1) Labor - $316,057 increase due to increased headcount and wage increases; (2) Employee Expenses - $123,325 increase related in part to increased headcount; (3) Maintenance Fees and Services - $109,704 increase related to software maintenance; (4) Legal Services - $78,324 increase due to anticipated increased activity; and (5) Management Fee Transfers - $175,502 increase in the amount transferred to balance sheet, which results in a decrease to expense, reflecting growth in NCSC functions providing services that are capital in nature.

COLUMBIA GAS OF KENTUCKY, INC.
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9. Refer to Volume 8 of the application, Tab F.

a. See Schedule F-1, page 1. For the American Gas Association, the Kentucky Gas Association, and the Southern Gas Association, provide separately the percentage of each organization's activities that is related to lobbying activities.

b. See Schedule F-1, page 1. Provide the purpose of the $7,500 payment to the University of Missouri and describe the benefits ratepayers receive from this. Provide the amount of any payments to universities plus the costs of lobbying activities allocated to Columbia by NiSource, Inc. ("NiSource") or any NiSource affiliate or subsidiary that is included in the base period or forecasted period cost-of-service.

c. See Schedule F-4, page 1. Describe the benefits ratepayers receive from the amounts shown here for employee parties, outings, and gifts included in Columbia's cost-of-service. Provide the amount of any employee parties, outings and gifts allocated to Columbia by NiSource or any NiSource affiliate or subsidiary that are included in the base period or forecasted period cost-of-service.

d. See Schedule F-5, page 1, Account No. 908, Account 909, Account 910, Account 912, and Account 913. Provide separately for each account, examples of the type of expenditures recorded in the account and an explanation of their purpose.

e. Schedule F-6, page 1, Community Support and Other. Provide examples of the type of expenditures recorded in this account and an explanation of their purpose.

f. See Schedule F-7, page 1, Consulting Services. Provide a schedule showing the names and the associated amounts paid, along with an explanation of the purpose of the expenditures recorded in professional service expense.

g. See Schedule F-9, page 1, Political Activities. Provide the following information:

(1) The account(s) in which any costs associated with lobbying activities are recorded.

(2) An explanation of the purpose of expenditures recorded for political activities reflected on this schedule.

(3) An explanation for why the amount spent on political activities is projected to increase by 40 percent from the base period to the forecasted period.

Response:

a. The American Gas Association states that approximately three percent of its activities relate to lobbying. The Kentucky Gas Association and the Southern Gas Association do not identify a percentage related to lobbying.

b. The payment to the University of Missouri represents Columbia's membership in the university's Financial Research Institute which, through its public utility division, provides an environment for stakeholders in the regulated public utility industry to discuss issues relating to public utility policy. The Institute hosts an annual symposium with industry and regulatory leaders as well as monthly hotline calls for its members on industry topics. Through the Institute, Columbia has access to current industry and regulatory information for improved business practices.

c. The amounts included on Schedule No. F-4 are being provided to comply with filing regulations. These amounts have been removed from Columbia's cost of service as part of adjustment no. 10 in Schedule D-2.4.Account 908 includes expenses related to Columbia's Energy Efficiency/Conservation Program (EECP) including outside services, advertising, and tracker expense recognized to match the recovery of expenditures through the EECP rider. Account 909 includes public awareness advertising incurred by the NiSource Corporate Services Company (NCSC) Pipeline Safety and Compliance on behalf of Columbia. Account 910 includes gas transportation services of

NCSC Commercial Operations, large customer relations services and other customer interaction by NCSC Sales and Marketing on behalf of Columbia. Account 912 includes promotional expenses incurred by NCSC Sales and Marketing on behalf of Columbia. Account 913 includes promotional advertising incurred by NCSC Sales and Marketing on behalf of Columbia.

d. Community Support and Other primarily encompasses event sponsorships in the support of worthwhile organizations. Examples of organizations include Commerce Lexington, Women Leading Kentucky, Bluegrass Greenworks, Fayette County Public Schools, Minority Business Expo, Montgomery Council for the Arts, Down Syndrome Association of Central Kentucky, and Woodford Humane Society.

e. Please refer to Attachment A of this response.

f. (1) Costs associated with lobbying activities are recorded to Accounts 920, 921, and 923.

(2) Legislative lobbying activities are conducted through John "Brack" Marquette, the Columbia Director of Governmental Affairs and a registered legislative agent and executive branch agent for the purposes of tracking, proposing and analyzing legislation and regulatory action and providing Columbia with information and data on the impact to Columbia and its customers. Whitehouse/Riddle is a registered executive branch agent under

contract for Columbia to advise Columbia and analyze and assess the impact of executive branch policy and action on Columbia.

(3) The base period reflects amounts incurred in the actual portion of the period (September 2012 – February 2013) by Columbia's Director of Governmental Affairs for lobbying activities that are readily identifiable through separate reporting and the known actual and budgeted amounts for an external lobbying consultant. The forecasted test period reflects an assumption based on 2012 actual amounts incurred by the Director for lobbying activities and the known budget for the consultant. In addition, legislative activities will increase in 2014 due to the Kentucky General Assembly being in session for a longer period than in 2013. Please note that the forecasted test period amount is removed from O&M expense on Schedule D-2.4.

COLUMBIA GAS OF KENTUCKY, INC.
PROFESSIONAL SERVICE EXPENSES

	Base Period	Forecasted Period	Explanation:
Auditing Services			
Deloitte	155,747	180,900	Auditing services provided to NiSource including Columbia
IBM	14,874	-	Geographic Information System
Lexington-Fayette Urban County Government	10,641	-	Cost share audit - franchise fee agreement
Total Auditing Services	181,262	180,900	
Consulting Services			
Whitehouse Riddle	27,000	27,000	Lobbying services
Gannett Fleming	6,860	-	Depreciation study (reclassified to regulatory asset in different cost category)
Black & Veatch	11,640	-	Class cost of service and rate design (reclassified to regulatory asset in different cost category)
Midwest Environmental	1,596	-	Consulting services in conjunction with Mercer Rd. generator
Matrix Group	133	-	Telephone survey services & analysis
Meekins Resource Strategies	209	-	Project management and data analysis regarding Polypipe investigation and remediation
RCP Inc.	68,151	-	Maximum allowable operating pressure study
URS	2,311	-	Environmental compliance
Various vendors	128,840	211,700	Implementation of a single general ledger and chart of accounts for all NiSource companies including Columbia
FM Solutions	188	-	Kentucky facilities analysis
Other	34	-	
Field Operations Budget - Other	2,050	4,102	
President's Staff Budget - Other	2,748	5,500	
Total Consulting Services	251,760	248,302	
Total Professional Services	433,022	429,202	

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

10. Refer to Volume 8 of the application, Tab G, Schedule G-3.

a. Line 15 states, "This schedule reflects amounts allocated to Columbia for the following positions." Identify the entity allocating the amounts to Columbia and the methodology used in the allocation.

b. Provide a detailed explanation and support for the amounts in the "Other Allowances and Compensation" category on line 2, along with the allocation methodology used.

c. Provide a detailed explanation and support for the amounts in the "Other Benefits" category on line 7, along with the allocation methodology used.

Response:

a. The President is an employee of Columbia and allocates 100% to Columbia. The remaining individuals are employees of NiSource Corporate Services Company and allocate to Columbia using an allocation basis or bases appropriate for the NiSource companies for which they have responsibility.

Please refer to the direct testimony of Columbia witness Taylor for an explanation of the Bases of Allocation.

b. The amounts in Other Allowances and Compensation represent NiSource's Long Term Equity Incentive Plan, which is a stock compensation plan. The amount for Columbia's President is allocated 100% to Columbia. Amounts for the remaining individuals are allocated to NiSource companies using an allocation basis that reflects the companies for which they have responsibility.

c. Other benefits include medical, group life, dental, long-term disability, group life and thrift plan. For the Columbia President, an average cost per employee for Columbia was calculated for the base period and forecasted test period and included on Schedule G-3. For the other individuals, a percentage of benefits to total payroll for NiSource Corporate Services billings to Columbia was calculated for the base period and forecasted test period and applied to the base pay for each individual.

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11. Refer to Volume 8 of the application, Tab M. Provide an electronic copy of all schedules under this tab with the formulas intact and unprotected and all rows and columns accessible.

Response:

Please refer to the two files are included on a separate CD. The files are named "PSC DR Set 2 No. 11 Schedule M Forecasted Period" and "PSC DR Set 2 No. 11 Schedule M Base Period."

COLUMBIA GAS OF KENTUCKY, INC.
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12. Refer to Volume 8 of the application, Tab N, Page 1. Provide the calculations of the current and proposed bills of the GSR, General Service Residential class.

Response:

Please refer to Attachment A.

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167
Calculation of Current and Proposed GSR Bill

Line No.	Billing Items		Usage	Current Rate ($)	Current Bill ($)	Proposed Rate ($)	Proposed Bill ($)
1	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
2	AMRP Rider	$/Bill		1.06	1.06	-	-
3	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
4	Gas Delivery Charge	$/Mcf	1.0	1.8715	1.87	2.4322	2.43
5	Gas Supply Cost (GCA)	$/Mcf	1.0	4.0634	4.06	4.0634	4.06
6	Uncollectible Gas Gost Rider	$/Mcf	1.0	0.0603	0.06	0.0243	0.02
7	Research and Development Factor	$/Mcf	1.0	0.0150	0.02	0.0150	0.02
8	Energy Assistance Program Surcharge	$/Mcf	1.0	0.0615	0.06	0.0615	0.06
9	Total				**19.24**		**24.85**
10	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
11	AMRP Rider	$/Bill		1.06	1.06	-	-
12	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
13	Gas Delivery Charge	$/Mcf	2.0	1.8715	3.74	2.4322	4.86
14	Gas Supply Cost (GCA)	$/Mcf	2.0	4.0634	8.13	4.0634	8.13
15	Uncollectible Gas Gost Rider	$/Mcf	2.0	0.0603	0.12	0.0243	0.05
16	Research and Development Factor	$/Mcf	2.0	0.0150	0.03	0.0150	0.03
17	Energy Assistance Program Surcharge	$/Mcf	2.0	0.0615	0.12	0.0615	0.12
18	Total				**25.31**		**31.45**
19	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
20	AMRP Rider	$/Bill		1.06	1.06	-	-
21	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
22	Gas Delivery Charge	$/Mcf	3.0	1.8715	5.61	2.4322	7.30
23	Gas Supply Cost (GCA)	$/Mcf	3.0	4.0634	12.19	4.0634	12.19
24	Uncollectible Gas Gost Rider	$/Mcf	3.0	0.0603	0.18	0.0243	0.07
25	Research and Development Factor	$/Mcf	3.0	0.0150	0.05	0.0150	0.05
26	Energy Assistance Program Surcharge	$/Mcf	3.0	0.0615	0.18	0.0615	0.18
27	Total				**31.38**		**38.05**
28	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
29	AMRP Rider	$/Bill		1.06	1.06	-	-
30	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
31	Gas Delivery Charge	$/Mcf	4.0	1.8715	7.49	2.4322	9.73
32	Gas Supply Cost (GCA)	$/Mcf	4.0	4.0634	16.25	4.0634	16.25
33	Uncollectible Gas Gost Rider	$/Mcf	4.0	0.0603	0.24	0.0243	0.10
34	Research and Development Factor	$/Mcf	4.0	0.0150	0.06	0.0150	0.06
35	Energy Assistance Program Surcharge	$/Mcf	4.0	0.0615	0.25	0.0615	0.25
36	Total				**37.46**		**44.65**
37	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
38	AMRP Rider	$/Bill		1.06	1.06	-	-
39	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
40	Gas Delivery Charge	$/Mcf	5.5	1.8715	10.29	2.4322	13.38
41	Gas Supply Cost (GCA)	$/Mcf	5.5	4.0634	22.35	4.0634	22.35
42	Uncollectible Gas Gost Rider	$/Mcf	5.5	0.0603	0.33	0.0243	0.13
43	Research and Development Factor	$/Mcf	5.5	0.0150	0.08	0.0150	0.08
44	Energy Assistance Program Surcharge	$/Mcf	5.5	0.0615	0.34	0.0615	0.34
45	Total				**46.56**		**54.54**

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167
Calculation of Current and Proposed GSR Bill

Line No.	Billing Items		Usage	Current Rate ($)	Current Bill ($)	Proposed Rate ($)	Proposed Bill ($)
1	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
2	AMRP Rider	$/Bill		1.06	1.06	-	-
3	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
4	Gas Delivery Charge	$/Mcf	6.0	1.8715	11.23	2.4322	14.59
5	Gas Supply Cost (GCA)	$/Mcf	6.0	4.0634	24.38	4.0634	24.38
6	Uncollectible Gas Gost Rider	$/Mcf	6.0	0.0603	0.36	0.0243	0.15
7	Research and Development Factor	$/Mcf	6.0	0.0150	0.09	0.0150	0.09
8	Energy Assistance Program Surcharge	$/Mcf	6.0	0.0615	0.37	0.0615	0.37
9	Total				**49.60**		**57.84**
10	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
11	AMRP Rider	$/Bill		1.06	1.06	-	-
12	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
13	Gas Delivery Charge	$/Mcf	8.0	1.8715	14.97	2.4322	19.46
14	Gas Supply Cost (GCA)	$/Mcf	8.0	4.0634	32.51	4.0634	32.51
15	Uncollectible Gas Gost Rider	$/Mcf	8.0	0.0603	0.48	0.0243	0.19
16	Research and Development Factor	$/Mcf	8.0	0.0150	0.12	0.0150	0.12
17	Energy Assistance Program Surcharge	$/Mcf	8.0	0.0615	0.49	0.0615	0.49
18	Total				**61.74**		**71.03**
19	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
20	AMRP Rider	$/Bill		1.06	1.06	-	-
21	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
22	Gas Delivery Charge	$/Mcf	10.0	1.8715	18.72	2.4322	24.32
23	Gas Supply Cost (GCA)	$/Mcf	10.0	4.0634	40.63	4.0634	40.63
24	Uncollectible Gas Gost Rider	$/Mcf	10.0	0.0603	0.60	0.0243	0.24
25	Research and Development Factor	$/Mcf	10.0	0.0150	0.15	0.0150	0.15
26	Energy Assistance Program Surcharge	$/Mcf	10.0	0.0615	0.62	0.0615	0.62
27	Total				**73.89**		**84.22**
28	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
29	AMRP Rider	$/Bill		1.06	1.06	-	-
30	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
31	Gas Delivery Charge	$/Mcf	12.0	1.8715	22.46	2.4322	29.19
32	Gas Supply Cost (GCA)	$/Mcf	12.0	4.0634	48.76	4.0634	48.76
33	Uncollectible Gas Gost Rider	$/Mcf	12.0	0.0603	0.72	0.0243	0.29
34	Research and Development Factor	$/Mcf	12.0	0.0150	0.18	0.0150	0.18
35	Energy Assistance Program Surcharge	$/Mcf	12.0	0.0615	0.74	0.0615	0.74
36	Total				**86.03**		**97.42**
37	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
38	AMRP Rider	$/Bill		1.06	1.06	-	-
39	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
40	Gas Delivery Charge	$/Mcf	16.0	1.8715	29.94	2.4322	38.92
41	Gas Supply Cost (GCA)	$/Mcf	16.0	4.0634	65.01	4.0634	65.01
42	Uncollectible Gas Gost Rider	$/Mcf	16.0	0.0603	0.96	0.0243	0.39
43	Research and Development Factor	$/Mcf	16.0	0.0150	0.24	0.0150	0.24
44	Energy Assistance Program Surcharge	$/Mcf	16.0	0.0615	0.98	0.0615	0.98
45	Total				**110.30**		**123.80**

Columbia Gas of Kentucky, Inc.
Case No. 2013-00167
Calculation of Current and Proposed GSR Bill

Line No.	Billing Items		Usage	Current Rate ($)	Current Bill ($)	Proposed Rate ($)	Proposed Bill ($)
1	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
2	AMRP Rider	$/Bill		1.06	1.06	-	-
3	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
4	Gas Delivery Charge	$/Mcf	18.0	1.8715	33.69	2.4322	43.78
5	Gas Supply Cost (GCA)	$/Mcf	18.0	4.0634	73.14	4.0634	73.14
6	Uncollectible Gas Gost Rider	$/Mcf	18.0	0.0603	1.09	0.0243	0.44
7	Research and Development Factor	$/Mcf	18.0	0.0150	0.27	0.0150	0.27
8	Energy Assistance Program Surcharge	$/Mcf	18.0	0.0615	1.11	0.0615	1.11
9	Total				**122.47**		**137.00**
10	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
11	AMRP Rider	$/Bill		1.06	1.06	-	-
12	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
13	Gas Delivery Charge	$/Mcf	22.0	1.8715	41.17	2.4322	53.51
14	Gas Supply Cost (GCA)	$/Mcf	22.0	4.0634	89.39	4.0634	89.39
15	Uncollectible Gas Gost Rider	$/Mcf	22.0	0.0603	1.33	0.0243	0.53
16	Research and Development Factor	$/Mcf	22.0	0.0150	0.33	0.0150	0.33
17	Energy Assistance Program Surcharge	$/Mcf	22.0	0.0615	1.35	0.0615	1.35
18	Total				**146.74**		**163.37**
19	Monthly Customer Charge	$/Bill		12.35	12.35	18.50	18.50
20	AMRP Rider	$/Bill		1.06	1.06	-	-
21	EECP Rider	$/Bill		(0.24)	(0.24)	(0.24)	(0.24)
22	Gas Delivery Charge	$/Mcf	25.0	1.8715	46.79	2.4322	60.81
23	Gas Supply Cost (GCA)	$/Mcf	25.0	4.0634	101.59	4.0634	101.59
24	Uncollectible Gas Gost Rider	$/Mcf	25.0	0.0603	1.51	0.0243	0.61
25	Research and Development Factor	$/Mcf	25.0	0.0150	0.38	0.0150	0.38
26	Energy Assistance Program Surcharge	$/Mcf	25.0	0.0615	1.54	0.0615	1.54
27	Total				**164.98**		**183.19**

Note: Columbia's current rates at the time of filing the Application were as of February 28, 2013

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

13. Refer to Volume 9 of the application, the Direct Testimony of Herbert A. Miller, Jr. ("Miller Testimony"). On page 9, beginning at line 14, Mr. Miller refers to Columbia's participation in quarterly surveys of J.D. Power & Associates. In the sentence beginning on line 15, Mr. Miller states, "Although it is the smallest of the survey participants, Columbia continues to rank favorably among Kentucky gas distribution companies in the survey from an overall customer satisfaction perspective."

a. Identify the specific quarterly periods in the surveys to which Mr. Miller refers.

b. Identify how the size of the survey participants is measured.

c. Based on publicly available information on file at the Commission, both in annual revenues and customers, Columbia is third in size among jurisdictional Kentucky local gas distribution companies ("LDCs"). Identify the other Kentucky LDCs that participated in the J.D. Power & Associates surveys referenced by Mr. Miller.

d. Provide a summary of the survey results referenced by Mr. Miller.

Response:

a. Surveying is conducted quarterly and reported annually. The specific survey periods are as follows: September/October (Wave 1), December/January (Wave 2), March/April (Wave 3) and June/July (Wave 4). The annual press release is held in September.

b. J.D. Power attempts to collect 600 completed interviews on an annual basis for all of the utilities they measure. In 2012, J.D. Power surveyed 527 Columbia Gas of Kentucky customers.

c. J.D. Power & Associates measures the following LDC's within Kentucky for their Residential Gas syndicated study: Atmos Energy – South, Duke Energy, Louisville Gas & Electric

d. Columbia Gas of Kentucky (636 points) ranks second in Overall Customer Satisfaction within the Commonwealth of Kentucky in the 2012 J.D. Power Residential Gas Study, just below Atmos Energy – South (649 points), but above Duke Energy (629 points) and Louisville Gas & Electric (626 points).

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

14. Refer to page 10 of the Miller Testimony, beginning at line 10. For each of the statistics for which Mr. Miller provides comparisons between 2009 and 2012 results, provide the same statistics for the years 2008, 2010, and 2011.

Response:

Leaks per mile of main:
- 2008: 0.17
- 2010: 0.15
- 2011: 0.13

OSHA Recordable Injury Rate:
- 2008: 3.09
- 2010: 0.07
- 2011: 3.69

DART Rate:
- 2008: 1.85
- 2010: 0.00
- 2011: 3.61

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

15. Refer to page 10 of the Miller Testimony, starting at line 18 and continuing to page 11, line 6. Mr. Miller identifies three specific employee positions Columbia plans to add which are included "[i]n the forecasted revenue requirement. . . ." According to Volume 8, Schedule G-2, of the application, the average number of employees in Columbia's forecasted test period, 129, represents an increase of 11 over the average number, 118, it had in both 2011 and 2012.

a. Provide the number of employees on Columbia's payroll at June 30, 2013.

b. Aside from the three specific positions referenced by Mr. Miller, explain why Columbia intends to add eight additional employees above the number with which it operated during the past two calendar years.

c. For the 11 employees that reflect an increase above the average number of employees in calendar year 2012, provide the amount of expense included in the forecasted test period for 1) salaries and wages and 2) employee benefits.

Response:

a. Columbia has 126 employees on its payroll as of June 2013, of which 124 are full-time and 2 are part-time.

b. Columbia continually works to ensure adequate staffing to meet projected workload requirements. As June actual headcount indicates, Columbia has experienced increased headcount over the historic levels of 2011 and 2012, mainly in Field Operations. During the past several years, Operations has lost dozens of employees due to movement within NiSource and retirements. Columbia has been hiring new employees throughout 2012 and 2013, but until now has not been able to reach the desired staffing level to continue to provide the desired customer service levels and qualified employees to perform necessary tasks.

c. The addition of three employees related to the Distribution Integrity Management Program results in approximately $178,839 of labor expense and $29,580 of benefits expense in the forecasted test period. The addition of the eight remaining employees results in approximately $528,093 of labor expense and $78,880 of benefits expense. As indicated in the response to part (a), a portion of this increased expense in the forecasted test period as compared to 2011 and 2012 actual employee levels has been realized during 2013.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

16. Refer to page 12 of the Miller Testimony, beginning at line 10, where he begins a discussion of Columbia's plans to install Automated Meter Reading ("AMR") devices. Starting on line 13, Mr. Miller states "However, once all the devices are installed by the end of 2014 . . . cost reductions will be realized for Columbia customers which savings have been included in Columbia's revenue requirement in this case."

a. Provide the amount of savings that has been included in Columbia's revenue requirement in its application and a detailed explanation of how the amount was determined, along with any supporting workpapers and calculations.

b. Given that the AMR devices are to be installed during calendar year 2014, Columbia's forecasted test period, explain whether the savings included in its revenue requirement reflect a full 12-month savings, post-installation, or the incremental savings projected during 2014, when the devices will not be installed for the entire year.

Response:

a. The amount of savings included in Columbia's revenue requirement is $199,731. It was determined by comparing historic monthly manual meter reading cost to the projected monthly automated meter reading cost. This savings represents a percentage of the total annual ongoing savings ultimately to be achieved once installation of AMR devices is completed.

b. The installation of AMR devices is scheduled over the course of 2014 and is expected to result in outside services savings starting in the fourth quarter of 2014, once the saturation of AMR devices has resulted in the initial transitions from manual meter reading to automated meter reading.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

17. Refer to the Miller Testimony, page 13, lines 7-8. Mr. Miller states that under Columbia's Accelerated Main Replacement Program ("AMRP") 400,000 feet of pipe has been replaced since 2008.

a. Provide the specific date that Columbia began replacing pipe under the program and the date on which it reached 400,000 feet having been replaced.

b. Describe how replacing 400,000 feet of pipe by the date identified in response to part a. of this request compares to the amount of pipe Columbia had projected to have replaced by that date.

Response:

a. Columbia completes and submits an annual Department of Transportation (DOT) report of the miles pipe in its distribution system for each calendar year. Columbia utilized this report for each year from 2008 through 2012 to provide the amount of pipe retired under the AMRP. Therefore, the start date for the five year period runs from January 1, 2008 through December 31, 2012.

In Mr. Miller's testimony, it stated that Columbia replaced "approximately" 400,000 feet of priority pipe since 2008. Based on the DOT report for 2012 compared to 2008, Columbia retired 70.3 miles of pipe under the AMRP which equates to 371,184 feet.

b. Columbia did not establish a projection or goal of pipe that it planned to retire by the end of 2012. The focus has been to accelerate the replacement of this pipe with the expectation that the program will be completed over a 30 year period beginning in 2008.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

18. Refer to pages 15-16 of the Miller Testimony, specifically, the discussion of Columbia's request regarding a slippage factor in which he cites AMRP construction being a "materially large" component of Columbia's capital construction budget, and Attachment B to the response to Item 13 of Commission Staffs First Request for Information ("Staffs First Request").

a. For each year from 2008 through 2012, provide the amounts of Columbia's budgeted and actual capital construction expenditures, separated into AMRP construction and non-AMRP construction.

b. Provide the calculation of the five-year 8.2 percent positive slippage rate reference on page 15, lines 11-13 of the Miller Testimony.

c. Clarify whether the information contained in Attachment B to the data response includes all of Columbia's construction in recent years, both AMRP and non-AMRP.

d. If the response to part c. of this request is yes, provide the annual amounts of budgeted and actual non-AMRP construction and the related slippage calculations for the years 2003 through 2012.

Response:

a. See Staff Set 2 DR No. 18 Attachment A

b. From 2008 – 2012, Columbia's total capital approved budget was $64.6 million. Columbia's capital expenditures for this same time period totaled $69.9 million. Columbia spent an additional $5.3 million dollars over five years when compared to the original budget of $64.6 million which represents a positive variance of 8.2 percent.

c. Yes, the information contained in Attachment B to the response to Item 13 of Commission Staff's First Request includes all of Columbia's construction in recent years, both AMRP and non-AMRP.

d. Columbia's processes and capital status reports did not track AMRP and non-AMRP expenditures separately prior to 2009. See Columbia's response to Staff data request Set 2 DR No.18 Attachment A for the annual amounts of budgeted and actual non-AMRP construction and the related variance calculations for the years 2009 through 2012.

CKY Historical Budget vs Actual
($000,000)

Business Class	2008	2009	2010	2011	2012
	0&12 Dec-YTD Budget	0&12 Dec-YTD Budget	0&12 Dec-YTD Budget	0&12 Dec-YTD Budget	0&12 Dec-YTD Budget
Non AMRP	14.7	5.8	5.3	4.8	5.5
*AMRP		7.1	4.9	7.4	9.1
Totals	14.7	12.9	10.3	12.2	14.7
	Dec-YTD Actual	Dec-YTD Actual	Dec-YTD Actual	Dec-YTD Actual	Dec-YTD Actual
Non AMRP	13.6	3.9	5.4	5.1	7.5
*AMRP		9.1	4.8	9.2	11.4
Totals	13.6	13.0	10.1	14.3	18.9
	Variance (Fav)/Unfav	Variance (Fav)/Unfav	Variance (Fav)/Unfav	Variance (Fav)/Unfav	Variance (Fav)/Unfav
Non AMRP	(1.1)	(1.9)	0.0	0.3	2.0
*AMRP	-	2.0	(0.2)	1.9	2.2
Totals	(1.1)	0.1	(0.1)	2.2	4.3

*Note AMRP not categorized prior to 2009
2009-2012 Only:

	2009	2010	2011	2012
Non AMRP				
Variance %	-33.0%	0.5%	6.6%	36.4%
Cumulative Variance %	-33.0%	-16.9%	-9.8%	2.2%
AMRP				
Variance %	28.7%	-3.1%	25.4%	24.5%
Cumulative Variance %	28.7%	15.7%	25.4%	21.0%
Totals				
Variance %	1.1%	-1.3%	18.0%	29.0%
Cumulative Variance %	1.1%	0.1%	6.2%	12.9%

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

19. Refer to Volume 9 of the application, the Direct Testimony of Judy M. Cooper ("Cooper Testimony").

a. Page 16, line 6, refers to "tools for evaluating participation" in terms of price and other comparisons that customers could be provided to customers in the Customer CHOICE ("CHOICE") program. State whether Columbia is willing to provide its customers, both those participating and eligible to participate in the CHOICE program, an annual statement showing their gas cost at Columbia's Gas Cost Adjustment rate and at average, or individual, gas marketer rates.

b. State what improvements could be made with regard to the Commission's oversight over marketer participation, as indicated in lines 8 and 9 of page 16.

c. Page 17 of the Cooper Testimony discusses the high customer-satisfaction level indicated by the 2012 CHOICE survey, which was filed into the record of Case No. 2012-00132.[1] State whether some customers

[1] Case No. 2012-00132, Columbia Gas of Kentucky, Inc. Filing of Customer Choice Survey Results, Final Report filed July 13, 2012.

indicating satisfaction with their participation in the CHOICE program were not, in fact, CHOICE customers.

d. The "Insights" section of the Final Report regarding the Choice survey concluded with the following paragraph on page 8 of the report:

> "While satisfaction with the Customer Choice program is high, this study revealed that customer perceptions of the Choice program are muddled by a number of factors. First, many people do not know what the program is, what the benefits of joining are, or how to join. Second, it seems that many customers are confusing the Customer Choice program with the Budget Payment Plan. Third, customers do not know how to track their savings or compare the costs of marketers in the program. For the Customer Choice program to be most transparent and effective, and for customer perceptions of the program to be uninfluenced by other factors like the Budget Payment Plan, consumers need to be better informed about the options available to them. Only then can the Choice program be truly evaluated on its own merits."

Explain how Columbia intends to address each factor identified above.

e. Refer to Attachment JMC-1 of the Cooper Testimony. Provide this same information, broken down by marketer, for the same time period.

Response:

a. Columbia has been investigating the possibility of showing its rate per Mcf on customer bills, both CHOICE participants and CHOICE-eligible customers, to make it easier to compare prices and promote awareness. This would provide customers the opportunity to act upon real-time information rather than a historical look-back. Columbia has also been considering an annual disclosure statement, a historical look-back, to CHOICE participants similar to that suggested that would be provided by the customer's CHOICE marketer on an annual basis. Columbia envisions the annual disclosure statement would be a means of direct communication between the customer and the marketer, therefore helping to reinforce to the customer their participation status, and provide the name, marketer contact information, Columbia contact information, and a 12- month summary of billed rate comparison information. The combination of providing increased information monthly on bills rendered by Columbia and an annual disclosure statement from marketers are two tools to better inform customers of the CHOICE program. Columbia notes that no costs were included in the base period or the forecasted test period associated with these ideas.

Columbia reasons that increasing messaging on customer bills will present customers with easy access to timely information on the CHOICE program. Details are not final, but the information furnished will be tailored to the participation status of the customer. Currently, bills rendered to CHOICE participants identify the name of the marketer chosen by the customer and the rate per Mcf that is being billed pursuant to the customer's agreement with the marketer. This information will be preserved. The annual disclosure statement would provide a historical picture for the customer and could also remind customers to watch their monthly bill for current information.

b. The Commission's oversight of marketer participation is indirect through Columbia. Columbia suggests an additional requirement for an annual disclosure statement, as described above, would be an improvement in Commission oversight. Columbia has no other specific recommendations at this time.

c. Respondents to the survey self-identified themselves as either a current CHOICE , previous CHOICE or never CHOICE participant. In some cases, that identification did not match the classification provided by Columbia. Some of this would be expected by customer movement over time, but the number of mismatches was greater than expected. However, there is also no way to be certain that the respondent was the same individual that may have made the decision regarding participation initially.

d. Please refer to response to part a. The factors identified in the "Insights" section of the report are not necessarily singularly identifiable or correctable. Columbia intends to address the factors both in combination and to the individual customer segments of CHOICE eligible and CHOICE participants as is appropriate to best reach all of the customers. e. All of the information is not available by marketer. The CHOICE volumes and marketer billing information that is available by marketer is attached hereto as Attachment A.

RS5500MK
CURRENT DATE: 04/30/11

COLUMBIA CHOICE PROGRAM - APRIL 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 04 / 2011
GAS BILLING CYCLE: 03 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 11	GTS-RES CHOICE - HEAT	03	184	1,202.4	8,286.28	.00	8,120.56	.00	8,120.56
32	04 11	GTS-RES CHOICE - NON-HEAT	05	2	5.6	38.62	.00	37.85	.00	37.85
32	04 11	TOTAL RESIDENTIAL		186	1,208.0	8,324.90	.00	8,158.41	.00	8,158.41
32	04 11	TOTAL COMMERCIAL			.0	.00	.00	8,158.41	.00	8,158.41
32	04 11	TOTAL		186	1,208.0	8,324.90	.00	8,158.41	.00	8,158.41

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 186 TIMES $ .200 = 37.20

xxxxxxxxxx COLUMBIA MCF CHARGE 1,208.0 TIMES $ .050 = 60.40

RS550MK
CURRENT DATE: 04/30/11

COLUMBIA CHOICE PROGRAM - APRIL 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : IGS ENERGY

DIS BILLING CYCLE: 04 / 2011
GAS BILLING CYCLE: 03 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 11	GTS-RES CHOICE - HEAT	03	21,711	158,745.6	1,109,218.23	.00	1,087,034.02	.00	1,087,034.02
32	04 11	GTS-RES CHOICE - NON-HEAT	05	223	555.9	4,014.70	.00	3,934.41	.00	3,934.41
32	04 11	TOTAL RESIDENTIAL		21,934	159,301.5	1,113,232.93	.00	1,090,968.43	.00	1,090,968.43
32	04 11	GTS-COM CHOICE - HEAT	04	2,184	95,275.7	679,385.20	.00	665,797.62	.00	665,797.62
32	04 11	GTS-COM CHOICE - NON-HEAT	08	138	741.2	5,137.28	.00	5,034.55	.00	5,034.55
32	04 11	GTS-COM CHOICE - HEAT&A/C	13	2	55.9	363.35	.00	356.08	.00	356.08
32	04 11	TOTAL COMMERCIAL		2,324	96,072.8	684,885.83	.00	1,762,156.68	.00	1,762,156.68
32	04 11	GTS-IND CHOICE - ALL	06	5	2,156.6	15,081.73	.00	14,780.10	.00	14,780.10
32	04 11	TOTAL		24,263	257,530.9	1,813,200.49	.00	1,776,936.78	.00	1,776,936.78

>>>>>>>>>> # OF CUSTOMERS BILLED BY COLUMBIA 24,263 TIMES $ .200 = 4,852.60

>>>>>>>>>> COLUMBIA MCF CHARGE 257,530.9 TIMES $ .050 = 12,876.55

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 3 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 04/30/11

COLUMBIA CHOICE PROGRAM - APRIL 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 04 / 2011
GAS BILLING CYCLE: 03 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 11	GTS-RES CHOICE - HEAT	03	4,700	34,105.2	267,618.83	.00	262,266.49	.00	262,266.49
32	04 11	GTS-RES CHOICE - NON-HEAT	05	46	72.5	566.40	.00	555.07	.00	555.07
32	04 11	TOTAL RESIDENTIAL		4,746	34,177.7	268,185.23	.00	262,821.56	.00	262,821.56
32	04 11	GTS-COM CHOICE - HEAT	04	646	27,605.5	199,732.21	.00	195,737.62	.00	195,737.62
32	04 11	GTS-COM CHOICE - NON-HEAT	08	21	255.8	1,802.48	.00	1,766.42	.00	1,766.42
32	04 11	TOTAL COMMERCIAL		667	27,861.3	201,534.69	.00	460,325.60	.00	460,325.60
32	04 11	GTS-IND CHOICE - ALL	06	4	2,631.0	21,083.52	.00	20,661.85	.00	20,661.85
32	04 11	TOTAL		5,417	64,670.0	490,803.44	.00	480,987.45	.00	480,987.45

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 5,417 TIMES $ .200 = 1,083.40

xxxxxxxxxx COLUMBIA MCF CHARGE 64,670.0 TIMES $ .050 = 3,233.50

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS550HK
CURRENT DATE: 04/30/11

COLUMBIA CHOICE PROGRAM - APRIL 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 04 / 2011
GAS BILLING CYCLE: 03 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 11	GTS-RES CHOICE - HEAT	03	1	11.5	73.76	.00	72.28	.00	72.28
32	04 11	TOTAL RESIDENTIAL		1	11.5	73.76	.00	72.28	.00	72.28
32	04 11	GTS-COM CHOICE - HEAT	04	65	7,141.2	45,803.67	.00	44,887.59	.00	44,887.59
32	04 11	TOTAL COMMERCIAL		65	7,141.2	45,803.67	.00	44,959.87	.00	44,959.87
32	04 11	GTS-IND CHOICE - ALL	06	1	95.8	614.46	.00	602.17	.00	602.17
32	04 11	TOTAL		67	7,248.5	46,491.89	.00	45,562.04	.00	45,562.04

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 67 TIMES $ .200 = 13.40

xxxxxxxxxx COLUMBIA MCF CHARGE 7,248.5 TIMES $ .050 = 362.43

RS5500MX
CURRENT DATE: 04/30/11

COLUMBIA CHOICE PROGRAM - APRIL 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 04 / 2011
GAS BILLING CYCLE: 03 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 11	GTS-RES CHOICE - HEAT	03	1,827	12,196.7	70,559.69	.00	69,148.55	.00	69,148.55
32	04 11	GTS-RES CHOICE - NON-HEAT	05	32	40.1	232.20	.00	227.56	.00	227.56
32	04 11	TOTAL RESIDENTIAL		1,859	12,236.8	70,791.89	.00	69,376.11	.00	69,376.11
32	04 11	GTS-COM CHOICE - HEAT	04	1,197	37,597.9	218,211.95	.00	213,847.71	.00	213,847.71
32	04 11	GTS-COM CHOICE - NON-HEAT	08	22	793.6	4,599.87	.00	4,507.87	.00	4,507.87
32	04 11	TOTAL COMMERCIAL		1,219	38,391.5	222,811.82	.00	287,731.69	.00	287,731.69
32	04 11	GTS-IND CHOICE - ALL	06	4	129.3	761.97	.00	746.73	.00	746.73
32	04 11	TOTAL		3,082	50,757.6	294,365.68	.00	288,478.42	.00	288,478.42

********** # OF CUSTOMERS BILLED BY COLUMBIA 3,082 TIMES $ .200 = 616.40

********** COLUMBIA MCF CHARGE 50,757.6 TIMES $ .050 = 2,537.88

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 06/01/11

COLUMBIA CHOICE PROGRAM - MAY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 05 / 2011
GAS BILLING CYCLE: 04 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 11	GTS-RES CHOICE - HEAT	03	183	530.1	3,726.46	.00	3,651.94	.00	3,651.94
32	05 11	GTS-RES CHOICE - NON-HEAT	05	2	4.7	33.01	.00	32.35	.00	32.35
32	05 11	TOTAL RESIDENTIAL		185	534.8	3,759.47	.00	3,684.29	.00	3,684.29
32	05 11	GTS-COM CHOICE - HEAT	04	1	5.7	47.59	.00	46.64	.00	46.64
32	05 11	TOTAL COMMERCIAL		1	5.7	47.59	.00	3,730.93	.00	3,730.93
32	05 11	TOTAL		186	540.5	3,807.06	.00	3,730.93	.00	3,730.93

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 186 TIMES $ .200 = 37.20

xxxxxxxxxx COLUMBIA MCF CHARGE 540.5 TIMES $ .050 = 27.03

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 06/01/11

COLUMBIA CHOICE PROGRAM - MAY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : IGS ENERGY

DIS BILLING CYCLE: 05 / 2011
GAS BILLING CYCLE: 04 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 11	GTS-RES CHOICE - HEAT	03	21,611	72,873.9	548,033.30	.00	537,072.76	.00	537,072.76
32	05 11	GTS-RES CHOICE - NON-HEAT	05	221	314.5	2,447.37	.00	2,398.42	.00	2,398.42
32	05 11	TOTAL RESIDENTIAL		21,832	73,188.4	550,480.67	.00	539,471.18	.00	539,471.18
32	05 11	GTS-COM CHOICE - HEAT	04	2,166	57,182.2	421,222.41	.00	412,797.93	.00	412,797.93
32	05 11	GTS-COM CHOICE - NON-HEAT	08	138	848.9	6,204.67	.00	6,080.58	.00	6,080.58
32	05 11	GTS-COM CHOICE - HEAT&A/C	13	2	11.5	82.80	.00	81.15	.00	81.15
32	05 11	TOTAL COMMERCIAL		2,306	58,042.6	427,509.88	.00	958,430.84	.00	958,430.84
32	05 11	GTS-IND CHOICE - ALL	06	5	2,413.8	17,068.59	.00	16,727.21	.00	16,727.21
32	05 11	TOTAL		24,143	133,644.8	995,059.14	.00	975,158.05	.00	975,158.05

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 24,143 TIMES $ .200 = 4,828.60

xxxxxxxxxx COLUMBIA MCF CHARGE 133,644.8 TIMES $ .050 = 6,682.24

RS5500HK
CURRENT DATE: 06/01/11

COLUMBIA CHOICE PROGRAM - MAY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 05 / 2011
GAS BILLING CYCLE: 04 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 11	GTS-RES CHOICE - HEAT	03	4,629	16,161.5	133,553.20	.00	130,882.16	.00	130,882.16
32	05 11	GTS-RES CHOICE - NON-HEAT	05	45	46.7	377.27	.00	369.73	.00	369.73
32	05 11	TOTAL RESIDENTIAL		4,674	16,208.2	133,930.47	.00	131,251.89	.00	131,251.89
32	05 11	GTS-COM CHOICE - HEAT	04	643	15,243.0	110,970.38	.00	108,751.02	.00	108,751.02
32	05 11	GTS-COM CHOICE - NON-HEAT	08	21	231.2	1,665.81	.00	1,632.51	.00	1,632.51
32	05 11	TOTAL COMMERCIAL		664	15,474.2	112,636.19	.00	241,635.42	.00	241,635.42
32	05 11	GTS-IND CHOICE - ALL	06	4	792.2	4,822.59	.00	4,726.14	.00	4,726.14
32	05 11	TOTAL		5,342	32,474.6	251,389.25	.00	246,361.56	.00	246,361.56

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 5,342 TIMES $ .200 = 1,068.40

xxxxxxxxxx COLUMBIA MCF CHARGE 32,474.6 TIMES $ .050 = 1,623.73

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 06/01/11

COLUMBIA CHOICE PROGRAM - MAY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 05 / 2011
GAS BILLING CYCLE: 04 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 11	GTS-RES CHOICE - HEAT	03	1	11.3	69.57	.00	68.18	.00	68.18
32	05 11	TOTAL RESIDENTIAL		1	11.3	69.57	.00	68.18	.00	68.18
32	05 11	GTS-COM CHOICE - HEAT	04	67	2,973.7	18,383.82	.00	18,016.15	.00	18,016.15
32	05 11	TOTAL COMMERCIAL		67	2,973.7	18,383.82	.00	18,084.33	.00	18,084.33
32	05 11	GTS-IND CHOICE - ALL	06	1	74.1	456.23	.00	447.11	.00	447.11
32	05 11	TOTAL		69	3,059.1	18,909.62	.00	18,531.44	.00	18,531.44

********** # OF CUSTOMERS BILLED BY COLUMBIA 69 TIMES $ .200 = 13.80

********** COLUMBIA MCF CHARGE 3,059.1 TIMES $ .050 = 152.96

PSC CASE NO. 2013-00167
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CURRENT DATE: 06/01/11

COLUMBIA CHOICE PROGRAM - MAY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 05 / 2011
GAS BILLING CYCLE: 04 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 11	GTS-RES CHOICE - HEAT	03	1,800	5,689.0	35,212.72	.00	34,508.43	.00	34,508.43
32	05 11	GTS-RES CHOICE - NON-HEAT	05	31	21.2	131.42	.00	128.78	.00	128.78
32	05 11	TOTAL RESIDENTIAL		1,831	5,710.2	35,344.14	.00	34,637.21	.00	34,637.21
32	05 11	GTS-COM CHOICE - HEAT	04	1,199	20,495.9	126,416.66	.00	123,888.30	.00	123,888.30
32	05 11	GTS-COM CHOICE - NON-HEAT	08	22	751.2	4,649.94	.00	4,556.94	.00	4,556.94
32	05 11	TOTAL COMMERCIAL		1,221	21,247.1	131,066.60	.00	163,082.45	.00	163,082.45
32	05 11	GTS-IND CHOICE - ALL	06	4	63.1	387.39	.00	379.65	.00	379.65
32	05 11	TOTAL		3,056	27,020.4	166,798.13	.00	163,462.10	.00	163,462.10

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 3,056 TIMES $ .200 = 611.20

xxxxxxxxxx COLUMBIA MCF CHARGE 27,020.4 TIMES $ .050 = 1,351.02

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 07/01/11

COLUMBIA CHOICE PROGRAM - JUNE 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 06 / 2011
GAS BILLING CYCLE: 05 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 11	GTS-RES CHOICE - HEAT	03	181	301.1	2,131.06	.00	2,089.21	.00	2,089.21
32	06 11	GTS-RES CHOICE - NON-HEAT	05	2	3.9	27.03	.00	26.49	.00	26.49
32	06 11	TOTAL RESIDENTIAL		183	305.0	2,158.89	.00	2,115.70	.00	2,115.70
32	06 11	GTS-COM CHOICE - HEAT	04	1	1.2	10.02	.00	9.82	.00	9.82
32	06 11	TOTAL COMMERCIAL		1	1.2	10.02	.00	2,125.52	.00	2,125.52
32	06 11	TOTAL		184	306.2	2,168.91	.00	2,125.52	.00	2,125.52

********** # OF CUSTOMERS BILLED BY COLUMBIA 184 TIMES $ .200 = 36.80

********** COLUMBIA MCF CHARGE 306.2 TIMES $ .050 = 15.31

RS5500MK
CURRENT DATE: 07/01/11

COLUMBIA CHOICE PROGRAM - JUNE 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : IGS ENERGY

DIS BILLING CYCLE: 06 / 2011
GAS BILLING CYCLE: 05 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 11	GTS-RES CHOICE - HEAT	03	21,471	38,427.4	289,500.85	.00	283,710.90	.00	283,710.90
32	06 11	GTS-RES CHOICE - NON-HEAT	05	220	343.4	2,643.16	.00	2,590.25	.00	2,590.25
32	06 11	TOTAL RESIDENTIAL		21,691	38,770.8	292,144.01	.00	286,301.15	.00	286,301.15
32	06 11	GTS-COM CHOICE - HEAT	04	2,145	26,604.5	205,337.12	.00	201,230.35	.00	201,230.35
32	06 11	GTS-COM CHOICE - NON-HEAT	08	137	704.0	5,171.05	.00	5,067.63	.00	5,067.63
32	06 11	GTS-COM CHOICE - HEAT&A/C	13	2	5.7	41.04	.00	40.22	.00	40.22
32	06 11	TOTAL COMMERCIAL		2,284	27,314.2	210,549.21	.00	492,639.35	.00	492,639.35
32	06 11	GTS-IND CHOICE - ALL	06	5	2,176.1	15,387.46	.00	15,079.71	.00	15,079.71
32	06 11	TOTAL		23,980	68,261.1	518,080.68	.00	507,719.06	.00	507,719.06

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 23,980 TIMES $ .200 = 4,796.00

xxxxxxxxxx COLUMBIA MCF CHARGE 68,261.1 TIMES $ .050 = 3,413.06

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RESPONDENT: JUDY M COOPER

RS5500HK
CURRENT DATE: 07/01/11

COLUMBIA CHOICE PROGRAM - JUNE 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 06 / 2011
GAS BILLING CYCLE: 05 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 11	GTS-RES CHOICE - HEAT	03	4,540	8,187.3	67,361.88	.00	66,014.82	.00	66,014.82
32	06 11	GTS-RES CHOICE - NON-HEAT	05	43	32.4	271.92	.00	266.50	.00	266.50
32	06 11	TOTAL RESIDENTIAL		4,583	8,219.7	67,633.80	.00	66,281.32	.00	66,281.32
32	06 11	GTS-COM CHOICE - HEAT	04	642	9,139.3	67,797.46	.00	66,441.53	.00	66,441.53
32	06 11	GTS-COM CHOICE - NON-HEAT	08	21	237.2	1,754.15	.00	1,719.06	.00	1,719.06
32	06 11	TOTAL COMMERCIAL		663	9,376.5	69,551.61	.00	134,441.91	.00	134,441.91
32	06 11	GTS-IND CHOICE - ALL	06	4	405.6	2,580.22	.00	2,528.61	.00	2,528.61
32	06 11	TOTAL		5,250	18,001.8	139,765.63	.00	136,970.52	.00	136,970.52

********** # OF CUSTOMERS BILLED BY COLUMBIA 5,250 TIMES $ .200 = 1,050.00

********** COLUMBIA MCF CHARGE 18,001.8 TIMES $ .050 = 900.09

RS5500MK
CURRENT DATE: 07/01/11

COLUMBIA CHOICE PROGRAM - JUNE 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 06 / 2011
GAS BILLING CYCLE: 05 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 11	GTS-RES CHOICE - HEAT	03	1	11.4	66.50	.00	65.17	.00	65.17
32	06 11	TOTAL RESIDENTIAL		1	11.4	66.50	.00	65.17	.00	65.17
32	06 11	GTS-COM CHOICE - HEAT	04	74	1,288.4	7,565.27	.00	7,413.97	.00	7,413.97
32	06 11	TOTAL COMMERCIAL		74	1,288.4	7,565.27	.00	7,479.14	.00	7,479.14
32	06 11	GTS-IND CHOICE - ALL	06	1	20.6-	126.83-	.00	124.29-	.00	124.29-
32	06 11	TOTAL		76	1,279.2	7,504.94	.00	7,354.85	.00	7,354.85

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 76 TIMES $ .200 = 15.20

xxxxxxxxxx COLUMBIA MCF CHARGE 1,279.2 TIMES $ .050 = 63.96

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 07/01/11

COLUMBIA CHOICE PROGRAM - JUNE 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 06 / 2011
GAS BILLING CYCLE: 05 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 11	GTS-RES CHOICE - HEAT	03	1,769	3,299.6	20,882.82	.00	20,465.17	.00	20,465.17
32	06 11	GTS-RES CHOICE - NON-HEAT	05	30	22.4	141.75	.00	138.92	.00	138.92
32	06 11	TOTAL RESIDENTIAL		1,799	3,322.0	21,024.57	.00	20,604.09	.00	20,604.09
32	06 11	GTS-COM CHOICE - HEAT	04	1,186	14,731.2	93,091.23	.00	91,229.39	.00	91,229.39
32	06 11	GTS-COM CHOICE - NON-HEAT	08	22	695.3	4,399.15	.00	4,311.17	.00	4,311.17
32	06 11	TOTAL COMMERCIAL		1,208	15,426.5	97,490.38	.00	116,144.65	.00	116,144.65
32	06 11	GTS-IND CHOICE - ALL	06	4	58.6	370.08	.00	362.68	.00	362.68
32	06 11	TOTAL		3,011	18,807.1	118,885.03	.00	116,507.33	.00	116,507.33

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 3,011 TIMES $ .200 = 602.20

xxxxxxxxxx COLUMBIA MCF CHARGE 18,807.1 TIMES $ .050 = 940.36

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 07/30/11

COLUMBIA CHOICE PROGRAM - JULY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 07 / 2011
GAS BILLING CYCLE: 06 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 11	GTS-RES CHOICE - HEAT	03	171	203.5	1,470.91	.00	1,441.49	.00	1,441.49
32	07 11	GTS-RES CHOICE - NON-HEAT	05	2	3.6	24.70	.00	24.21	.00	24.21
32	07 11	TOTAL RESIDENTIAL		173	207.1	1,495.61	.00	1,465.70	.00	1,465.70
32	07 11	GTS-COM CHOICE - HEAT	04	1	1.4	11.69	.00	11.46	.00	11.46
32	07 11	TOTAL COMMERCIAL		1	1.4	11.69	.00	1,477.16	.00	1,477.16
32	07 11	TOTAL		174	208.5	1,507.30	.00	1,477.16	.00	1,477.16

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 174 TIMES $ .200 = 34.80

xxxxxxxxxx COLUMBIA MCF CHARGE 208.5 TIMES $ .050 = 10.43

RS5500HK
CURRENT DATE: 07/30/11

COLUMBIA CHOICE PROGRAM - JULY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : IGS ENERGY

DIS BILLING CYCLE: 07 / 2011
GAS BILLING CYCLE: 06 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 11	GTS-RES CHOICE - HEAT	03	21,242	24,207.5	194,136.85	.00	190,254.77	.73-	190,254.77
32	07 11	GTS-RES CHOICE - NON-HEAT	05	220	269.7	2,170.54	.00	2,127.15	.00	2,127.15
32	07 11	TOTAL RESIDENTIAL		21,462	24,477.2	196,307.39	.00	192,381.92	.73-	192,381.92
32	07 11	GTS-COM CHOICE - HEAT	04	2,132	34,160.8	276,014.98	.00	270,494.71	.00	270,494.71
32	07 11	GTS-COM CHOICE - NON-HEAT	08	137	653.7	5,067.23	.00	4,965.90	.00	4,965.90
32	07 11	GTS-COM CHOICE - HEAT&A/C	13	2	6.7	52.46	.00	51.42	.00	51.42
32	07 11	TOTAL COMMERCIAL		2,271	34,821.2	281,134.67	.00	467,893.95	.73-	467,893.95
32	07 11	GTS-IND CHOICE - ALL	06	5	1,641.5	11,788.16	.00	11,552.40	.00	11,552.40
32	07 11	TOTAL		23,738	60,939.9	489,230.22	.00	479,446.35	.73-	479,446.35

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 23,738 TIMES $ .200 = 4,747.60

xxxxxxxxxx COLUMBIA MCF CHARGE 60,939.9 TIMES $ .050 = 3,047.00

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 18 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 07/30/11

COLUMBIA CHOICE PROGRAM - JULY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 07 / 2011
GAS BILLING CYCLE: 06 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 11	GTS-RES CHOICE - HEAT	03	4,423	5,334.8	43,938.11	.00	43,059.32	.00	43,059.32
32	07 11	GTS-RES CHOICE - NON-HEAT	05	43	24.7	208.41	.00	204.22	.00	204.22
32	07 11	TOTAL RESIDENTIAL		4,466	5,359.5	44,146.52	.00	43,263.54	.00	43,263.54
32	07 11	GTS-COM CHOICE - HEAT	04	645	7,743.4	57,153.90	.00	56,010.77	.00	56,010.77
32	07 11	GTS-COM CHOICE - NON-HEAT	08	21	268.1	1,986.18	.00	1,946.46	.00	1,946.46
32	07 11	TOTAL COMMERCIAL		666	8,011.5	59,140.08	.00	101,220.77	.00	101,220.77
32	07 11	GTS-IND CHOICE - ALL	06	4	43.4	519.94	.00	509.54	.00	509.54
32	07 11	TOTAL		5,136	13,414.4	103,806.54	.00	101,730.31	.00	101,730.31

********** # OF CUSTOMERS BILLED BY COLUMBIA 5,136 TIMES $ .200 = 1,027.20

********** COLUMBIA MCF CHARGE 13,414.4 TIMES $ .050 = 670.72

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 19 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 07/30/11

COLUMBIA CHOICE PROGRAM - JULY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 07 / 2011
GAS BILLING CYCLE: 06 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 11	GTS-RES CHOICE - HEAT	03	1	10.0	59.93	.00	58.73	.00	58.73
32	07 11	TOTAL RESIDENTIAL		1	10.0	59.93	.00	58.73	.00	58.73
32	07 11	GTS-COM CHOICE - HEAT	04	74	1,005.5	6,017.97	.00	5,897.62	.00	5.897.62
32	07 11	TOTAL COMMERCIAL		74	1,005.5	6,017.97	.00	5,956.35	.00	5,956.35
32	07 11	GTS-IND CHOICE - ALL	06	1	.0	.00	.00	.00	.00	.00
32	07 11	TOTAL		76	1,015.5	6,077.90	.00	5,956.35	.00	5,956.35

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 76 TIMES $ .200 = 15.20

xxxxxxxxxx COLUMBIA MCF CHARGE 1,015.5 TIMES $ .050 = 50.78

RS5500HK
CURRENT DATE: 07/30/11

COLUMBIA CHOICE PROGRAM - JULY 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 07 / 2011
GAS BILLING CYCLE: 06 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 11	GTS-RES CHOICE - HEAT	03	1,747	2,042.0	12,814.90	.00	12,558.76	.20-	12,558.76
32	07 11	GTS-RES CHOICE - NON-HEAT	05	30	24.2	151.88	.00	148.83	.00	148.83
32	07 11	TOTAL RESIDENTIAL		1,777	2,066.2	12,966.78	.00	12,707.59	.20-	12,707.59
32	07 11	GTS-COM CHOICE - HEAT	04	1,180	12,050.4	75,569.71	.00	74,058.34	.00	74,058.34
32	07 11	GTS-COM CHOICE - NON-HEAT	08	22	663.9	4,166.59	.00	4,083.26	.00	4,083.26
32	07 11	TOTAL COMMERCIAL		1,202	12,714.3	79,736.30	.00	90,849.19	.20-	90,849.19
32	07 11	GTS-IND CHOICE - ALL	06	4	23.2	145.86	.00	142.95	.00	142.95
32	07 11	TOTAL		2,983	14,803.7	92,848.94	.00	90,992.14	.20-	90,992.14

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 2,983 TIMES $ .200 = 596.60

xxxxxxxxxx COLUMBIA MCF CHARGE 14,803.7 TIMES $ .050 = 740.19

RS5500MK
CURRENT DATE: 09/01/11

COLUMBIA CHOICE PROGRAM - AUGUST 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 08 / 2011
GAS BILLING CYCLE: 07 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 11	GTS-RES CHOICE - HEAT	03	168	214.7	1,536.20	.00	1,505.46	.00	1,505.46
32	08 11	GTS-RES CHOICE - NON-HEAT	05	2	2.8	19.21	.00	18.83	.00	18.83
32	08 11	TOTAL RESIDENTIAL		170	217.5	1,555.41	.00	1,524.29	.00	1,524.29
32	08 11	GTS-COM CHOICE - HEAT	04	1	1.1	9.18	.00	9.00	.00	9.00
32	08 11	TOTAL COMMERCIAL		1	1.1	9.18	.00	1,533.29	.00	1,533.29
32	08 11	TOTAL		171	218.6	1,564.59	.00	1,533.29	.00	1,533.29

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 171 TIMES $ .200 = 34.20

xxxxxxxxxx COLUMBIA MCF CHARGE 218.6 TIMES $ .050 = 10.93

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 09/01/11

COLUMBIA CHOICE PROGRAM - AUGUST 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : IGS ENERGY

DIS BILLING CYCLE: 08 / 2011
GAS BILLING CYCLE: 07 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 11	GTS-RES CHOICE - HEAT	03	21,124	19,370.8	155,224.69	.00	152,120.28	.00	152,120.28
32	08 11	GTS-RES CHOICE - NON-HEAT	05	217	122.9	991.41	.00	971.59	.00	971.59
32	08 11	TOTAL RESIDENTIAL		21,341	19,493.7	156,216.10	.00	153,091.87	.00	153,091.87
32	08 11	GTS-COM CHOICE - HEAT	04	2,123	13,346.5	95,331.22	.00	93,424.54	.00	93,424.54
32	08 11	GTS-COM CHOICE - NON-HEAT	08	137	594.2	4,630.52	.00	4,537.90	.00	4,537.90
32	08 11	GTS-COM CHOICE - HEAT&A/C	13	2	5.3	41.66	.00	40.83	.00	40.83
32	08 11	TOTAL COMMERCIAL		2,262	13,946.0	100,003.40	.00	251,095.14	.00	251,095.14
32	08 11	GTS-IND CHOICE - ALL	06	5	1,968.1	14,036.93	.00	13,756.19	.00	13,756.19
32	08 11	TOTAL		23,608	35,407.8	270,256.43	.00	264,851.33	.00	264,851.33

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,608 TIMES $ .200 = 4,721.60

********** COLUMBIA MCF CHARGE 35,407.8 TIMES $ .050 = 1,770.39

RS5500MK
CURRENT DATE: 09/01/11

COLUMBIA CHOICE PROGRAM - AUGUST 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 08 / 2011
GAS BILLING CYCLE: 07 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 11	GTS-RES CHOICE - HEAT	03	4,350	4,410.4	36,226.38	.00	35,501.80	.00	35,501.80
32	08 11	GTS-RES CHOICE - NON-HEAT	05	42	25.3	210.92	.00	206.70	.00	206.70
32	08 11	TOTAL RESIDENTIAL		4,392	4,435.7	36,437.30	.00	35,708.50	.00	35,708.50
32	08 11	GTS-COM CHOICE - HEAT	04	645	7,510.7	54,403.14	.00	53,315.05	.00	53,315.05
32	08 11	GTS-COM CHOICE - NON-HEAT	08	21	204.0	1,510.69	.00	1,480.48	.00	1,480.48
32	08 11	TOTAL COMMERCIAL		666	7,714.7	55,913.83	.00	90,504.03	.00	90,504.03
32	08 11	GTS-IND CHOICE - ALL	06	4	35.0	403.58	.00	395.51	.00	395.51
32	08 11	TOTAL		5,062	12,185.4	92.754.71	.00	90,899.54	.00	90,899.54

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 5,062 TIMES $ .200 = 1,012.40

xxxxxxxxxx COLUMBIA MCF CHARGE 12,185.4 TIMES $ .050 = 609.27

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500HK
CURRENT DATE: 09/01/11

COLUMBIA CHOICE PROGRAM - AUGUST 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 08 / 2011
GAS BILLING CYCLE: 07 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 11	GTS-RES CHOICE - HEAT	03	1	11.2	82.40	.00	80.75	.00	80.75
32	08 11	TOTAL RESIDENTIAL		1	11.2	82.40	.00	80.75	.00	80.75
32	08 11	GTS-COM CHOICE - HEAT	04	74	819.7	6,010.61	.00	5,890.40	.00	5,890.40
32	08 11	TOTAL COMMERCIAL		74	819.7	6,010.61	.00	5,971.15	.00	5,971.15
32	08 11	GTS-IND CHOICE - ALL	06	1	.1	.74	.00	.73	.00	.73
32	08 11	TOTAL		76	831.0	6,093.75	.00	5,971.88	.00	5,971.88

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 76 TIMES $ .200 = 15.20

xxxxxxxxxx COLUMBIA MCF CHARGE 831.0 TIMES $ .050 = 41.55

RS550DHK
CURRENT DATE: 09/01/11

COLUMBIA CHOICE PROGRAM - AUGUST 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 08 / 2011
GAS BILLING CYCLE: 07 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 11	GTS-RES CHOICE - HEAT	03	1,722	1,711.5	10,790.47	.00	10,574.66	.00	10,574.66
32	08 11	GTS-RES CHOICE - NON-HEAT	05	30	15.2	95.87	.00	93.96	.00	93.96
32	08 11	TOTAL RESIDENTIAL		1,752	1,726.7	10,886.34	.00	10,668.62	.00	10,668.62
32	08 11	GTS-COM CHOICE - HEAT	04	1,175	10,427.0	65,727.33	.00	64,412.80	.00	64,412.80
32	08 11	GTS-COM CHOICE - NON-HEAT	08	22	602.5	3,799.55	.00	3,723.56	.00	3,723.56
32	08 11	TOTAL COMMERCIAL		1,197	11,029.5	69,526.88	.00	78,804.98	.00	78,804.98
32	08 11	GTS-IND CHOICE - ALL	06	4	22.5	141.66	.00	138.83	.00	138.83
32	08 11	TOTAL		2,953	12,778.7	80,554.88	.00	78,943.81	.00	78,943.81

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 2,953 TIMES $ .200 = 590.60

xxxxxxxxxx COLUMBIA MCF CHARGE 12,778.7 TIMES $ .050 = 638.94

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS550UMK
CURRENT DATE: 10/01/11

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 09 / 2011
GAS BILLING CYCLE: 08 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 11	GTS-RES CHOICE - HEAT	03	160	174.8	1,265.69	.00	1,240.37	.00	1,240.37
32	09 11	GTS-RES CHOICE - NON-HEAT	05	2	3.1	21.27	.00	20.84	.00	20.84
32	09 11	TOTAL RESIDENTIAL		162	177.9	1,286.96	.00	1,261.21	.00	1,261.21
32	09 11	GTS-COM CHOICE - HEAT	04	1	1.2	10.02	.00	9.82	.00	9.82
32	09 11	TOTAL COMMERCIAL		1	1.2	10.02	.00	1,271.03	.00	1,271.03
32	09 11	TOTAL		163	179.1	1,296.98	.00	1,271.03	.00	1,271.03

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 163 TIMES $ .200 = 32.60

xxxxxxxxxx COLUMBIA MCF CHARGE 179.1 TIMES $ .050 = 8.96

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 10/01/11

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : IGS ENERGY

DIS BILLING CYCLE: 09 / 2011
GAS BILLING CYCLE: 08 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 11	GTS-RES CHOICE - HEAT	03	20,996	25,124.4	190,889.62	.00	187,071.91	.00	187,071.91
32	09 11	GTS-RES CHOICE - NON-HEAT	05	217	190.8	1,514.36	.00	1,484.03	.00	1,484.03
32	09 11	TOTAL RESIDENTIAL		21,213	25,315.2	192,403.98	.00	188,555.94	.00	188,555.94
32	09 11	GTS-COM CHOICE - HEAT	04	2,115	26,635.6	205,665.90	.00	201,552.56	.00	201,552.56
32	09 11	GTS-COM CHOICE - NON-HEAT	08	135	599.2	4,610.89	.00	4,518.69	.00	4,518.69
32	09 11	GTS-COM CHOICE - HEAT&A/C	13	2	9.4	72.75	.00	71.30	.00	71.30
32	09 11	TOTAL COMMERCIAL		2,252	27,244.2	210,349.54	.00	394,698.49	.00	394,698.49
32	09 11	GTS-IND CHOICE - ALL	06	5	2,332.9	16,610.92	.00	16,278.70	.00	16,278.70
32	09 11	TOTAL		23,470	54,892.3	419,364.44	.00	410,977.19	.00	410,977.19

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 23,470 TIMES $ .200 = 4,694.00

xxxxxxxxxx COLUMBIA MCF CHARGE 54,892.3 TIMES $ .050 = 2,744.62

RS5500MK
CURRENT DATE: 10/01/11

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 09 / 2011
GAS BILLING CYCLE: 08 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 11	GTS-RES CHOICE - HEAT	03	4,301	5,275.0	43,201.44	.00	42,337.38	.00	42,337.38
32	09 11	GTS-RES CHOICE - NON-HEAT	05	42	22.1	187.34	.00	183.59	.00	183.59
32	09 11	TOTAL RESIDENTIAL		4,343	5,297.1	43,388.78	.00	42,520.97	.00	42,520.97
32	09 11	GTS-COM CHOICE - HEAT	04	644	9,643.5	70,241.33	.00	68,836.57	.10-	68,836.57
32	09 11	GTS-COM CHOICE - NON-HEAT	08	22	226.6	1,679.69	.00	1,646.11	.00	1,646.11
32	09 11	TOTAL COMMERCIAL		666	9,870.1	71,921.02	.00	113,003.65	.10-	113,003.65
32	09 11	GTS-IND CHOICE - ALL	06	4	38.2	421.37	.00	412.94	.00	412.94
32	09 11	TOTAL		5,013	15,205.4	115,731.17	.00	113,416.59	.10-	113,416.59

********** # OF CUSTOMERS BILLED BY COLUMBIA 5,013 TIMES $ .200 = 1,002.60

********** COLUMBIA MCF CHARGE 15,205.4 TIMES $ .050 = 760.27

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 29 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 10/01/11

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 09 / 2011
GAS BILLING CYCLE: 08 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 11	GTS-RES CHOICE - HEAT	03	1	10.8	73.41	.00	71.94	.00	71.94
32	09 11	TOTAL RESIDENTIAL		1	10.8	73.41	.00	71.94	.00	71.94
32	09 11	GTS-COM CHOICE - HEAT	04	74	1,271.2	8,674.52	.00	8,501.03	.00	8,501.03
32	09 11	TOTAL COMMERCIAL		74	1,271.2	8,674.52	.00	8,572.97	.00	8,572.97
32	09 11	GTS-IND CHOICE - ALL	06	1	3.2	21.75	.00	21.32	.00	21.32
32	09 11	TOTAL		76	1,285.2	8,769.68	.00	8,594.29	.00	8,594.29

********** # OF CUSTOMERS BILLED BY COLUMBIA 76 TIMES $ .200 = 15.20

********** COLUMBIA MCF CHARGE 1,285.2 TIMES $ .050 = 64.26

RS5500MK
CURRENT DATE: 10/01/11

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 09 / 2011
GAS BILLING CYCLE: 08 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 11	GTS-RES CHOICE - HEAT	03	1,697	2,007.0	12,682.22	.00	12,428.63	.00	12,428.63
32	09 11	GTS-RES CHOICE - NON-HEAT	05	30	19.2	121.35	.00	118.92	.00	118.92
32	09 11	TOTAL RESIDENTIAL		1,727	2,026.2	12,803.57	.00	12,547.55	.00	12,547.55
32	09 11	GTS-COM CHOICE - HEAT	04	1,163	11,602.0	73,295.02	.00	71,829.16	.00	71,829.16
32	09 11	GTS-COM CHOICE - NON-HEAT	08	22	628.0	3,968.94	.00	3,889.55	.00	3,889.55
32	09 11	TOTAL COMMERCIAL		1,185	12,230.0	77,263.96	.00	88,266.26	.00	88,266.26
32	09 11	GTS-IND CHOICE - ALL	06	4	35.9	226.55	.00	222.02	.00	222.02
32	09 11	TOTAL		2,916	14,292.1	90,294.08	.00	88,488.28	.00	88,488.28

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,916 TIMES $ .200 = 583.20

********** COLUMBIA MCF CHARGE 14,292.1 TIMES $ .050 = 714.61

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 11/01/11

COLUMBIA CHOICE PROGRAM - OCTOBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 10 / 2011
GAS BILLING CYCLE: 09 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 11	GTS-RES CHOICE - HEAT	03	157	310.0	2,328.99	.00	2,282.42	.00	2,282.42
32	10 11	GTS-RES CHOICE - NON-HEAT	05	2	2.8	19.21	.00	18.83	.00	18.83
32	10 11	TOTAL RESIDENTIAL		159	312.8	2,348.20	.00	2,301.25	.00	2,301.25
32	10 11	GTS-COM CHOICE - HEAT	04	1	4.2	33.56	.00	32.89	.00	32.89
32	10 11	TOTAL COMMERCIAL		1	4.2	33.56	.00	2,334.14	.00	2,334.14
32	10 11	TOTAL		160	317.0	2,381.76	.00	2,334.14	.00	2,334.14

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 160 TIMES $ .200 = 32.00

xxxxxxxxxx COLUMBIA MCF CHARGE 317.0 TIMES $ .050 = 15.85

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 11/01/11

COLUMBIA CHOICE PROGRAM - OCTOBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

DIS BILLING CYCLE: 10 / 2011
GAS BILLING CYCLE: 09 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 11	GTS-RES CHOICE - HEAT	03	20,902	41,984.1	332,613.94	.00	325,961.74	.03-	325,961.74
32	10 11	GTS-RES CHOICE - NON-HEAT	05	218	258.8	2,045.07	.00	2,004.17	.00	2,004.17
32	10 11	TOTAL RESIDENTIAL		21,120	42,242.9	334,659.01	.00	327,965.91	.03-	327,965.91
32	10 11	GTS-COM CHOICE - HEAT	04	2,102	34,270.8	260,741.46	.00	255,526.63	.00	255,526.63
32	10 11	GTS-COM CHOICE - NON-HEAT	08	137	650.0	4,982.89	.00	4,883.24	.00	4,883.24
32	10 11	GTS-COM CHOICE - HEAT&A/C	13	2	12.5	96.75	.00	94.81	.00	94.81
32	10 11	TOTAL COMMERCIAL		2,241	34,933.3	265,821.10	.00	588,470.59	.03-	588,470.59
32	10 11	GTS-IND CHOICE - ALL	06	5	2,228.5	15,891.39	.00	15,573.56	.00	15,573.56
32	10 11	TOTAL		23,366	79,404.7	616,371.50	.00	604,044.15	.03-	604,044.15

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 23,366 TIMES $ .200 = 4,673.20

xxxxxxxxxx COLUMBIA MCF CHARGE 79,404.7 TIMES $ .050 = 3,970.24

RS550MK
CURRENT DATE: 11/01/11

COLUMBIA CHOICE PROGRAM - OCTOBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : NXENERGY

DIS BILLING CYCLE: 10 / 2011
GAS BILLING CYCLE: 09 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 11	GTS-RES CHOICE - HEAT	03	4,250	8,954.2	73,323.58	.00	71,857.10	.00	71,857.10
32	10 11	GTS-RES CHOICE - NON-HEAT	05	42	27.9	232.36	.00	227.72	.00	227.72
32	10 11	TOTAL RESIDENTIAL		4,292	8,982.1	73,555.94	.00	72,084.82	.00	72,084.82
32	10 11	GTS-COM CHOICE - HEAT	04	637	11,725.0	85,239.06	.00	83,534.29	.00	83,534.29
32	10 11	GTS-COM CHOICE - NON-HEAT	08	21	246.8	1,829.60	.00	1,793.02	.00	1,793.02
32	10 11	TOTAL COMMERCIAL		658	11,971.8	87,068.66	.00	157,412.13	.00	157,412.13
32	10 11	GTS-IND CHOICE - ALL	06	4	43.8	243.53	.00	230.66	.00	230.66
32	10 11	TOTAL		4,954	20,997.7	160,868.13	.00	157,650.79	.00	157,650.79

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 4,954 TIMES $ .200 = 990.80

xxxxxxxxxx COLUMBIA MCF CHARGE 20,997.7 TIMES $ .050 = 1,049.89

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RESPONDENT: JUDY M COOPER

RS550HK
CURRENT DATE: 11/01/11

COLUMBIA CHOICE PROGRAM - OCTOBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 10 / 2011
GAS BILLING CYCLE: 09 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 11	GTS-RES CHOICE - HEAT	03	1	11.3	70.47	.00	69.06	.00	69.06
32	10 11	TOTAL RESIDENTIAL		1	11.3	70.47	.00	69.06	.00	69.06
32	10 11	GTS-COM CHOICE - HEAT	04	74	2,453.1	15,344.69	.00	15,037.81	.00	15,037.81
32	10 11	TOTAL COMMERCIAL		74	2,453.1	15,344.69	.00	15,106.87	.00	15,106.87
32	10 11	GTS-IND CHOICE - ALL	06	1	46.2	288.10	.00	282.34	.00	282.34
32	10 11	TOTAL		76	2,510.6	15,703.26	.00	15,389.21	.00	15,389.21

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 76 TIMES $ .200 = 15.20

xxxxxxxxxx COLUMBIA MCF CHARGE 2,510.6 TIMES $ .050 = 125.53

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RESPONDENT: JUDY M COOPER

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CURRENT DATE: 11/01/11

COLUMBIA CHOICE PROGRAM - OCTOBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 10 / 2011
GAS BILLING CYCLE: 09 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 11	GTS-RES CHOICE - HEAT	03	1,677	3,441.7	23,424.42	.00	22,955.94	.00	22,955.94
32	10 11	GTS-RES CHOICE - NON-HEAT	05	29	18.1	123.30	.00	120.84	.00	120.84
32	10 11	TOTAL RESIDENTIAL		1,706	3,459.8	23,547.72	.00	23,076.78	.00	23,076.78
32	10 11	GTS-COM CHOICE - HEAT	04	1,154	14,931.6	101,527.85	.00	99,497.29	.00	99,497.29
32	10 11	GTS-COM CHOICE - NON-HEAT	08	22	657.7	4,477.50	.00	4,387.94	.00	4,387.94
32	10 11	TOTAL COMMERCIAL		1,176	15,589.3	106,005.35	.00	126,962.01	.00	126,962.01
32	10 11	GTS-IND CHOICE - ALL	06	4	111.3	744.96	.00	730.06	.00	730.06
32	10 11	TOTAL		2,886	19,160.4	130,298.03	.00	127,692.07	.00	127,692.07

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,886 TIMES $ .200 = 577.20

********** COLUMBIA MCF CHARGE 19,160.4 TIMES $ .050 = 958.02

RS550OMK
CURRENT DATE: 12/01/11

COLUMBIA CHOICE PROGRAM - NOVEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 11 / 2011
GAS BILLING CYCLE: 10 / 2011

CO	MO	YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11	11	GTS-RES CHOICE - HEAT	03	154	789.6	5,974.84	.00	5,855.34	.00	5,855.34
32	11	11	GTS-RES CHOICE - NON-HEAT	05	2	3.0	20.58	.00	20.17	.00	20.17
32	11	11	TOTAL RESIDENTIAL		156	792.6	5,995.42	.00	5,875.51	.00	5,875.51
32	11	11	GTS-COM CHOICE - HEAT	04	1	12.4	92.88	.00	91.02	.00	91.02
32	11	11	TOTAL COMMERCIAL		1	12.4	92.88	.00	5,966.53	.00	5,966.53
32	11	11	TOTAL		157	805.0	6,088.30	.00	5,966.53	.00	5,966.53

********** # OF CUSTOMERS BILLED BY COLUMBIA 157 TIMES $ .200 = 31.40

********** COLUMBIA MCF CHARGE 805.0 TIMES $ .050 = 40.25

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RESPONDENT: JUDY M COOPER

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CURRENT DATE: 12/01/11

COLUMBIA CHOICE PROGRAM - NOVEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

IGS

DIS BILLING CYCLE: 11 / 2011
GAS BILLING CYCLE: 10 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 11	GTS-RES CHOICE - HEAT	03	21,190	114,958.7	909,352.43	.00	891,165.52	.00	891,165.52
32	11 11	GTS-RES CHOICE - NON-HEAT	05	238	375.0	2,992.23	.00	2,932.36	.00	2,932.36
32	11 11	TOTAL RESIDENTIAL		21,428	115,333.7	912,344.66	.00	894,097.88	.00	894,097.88
32	11 11	GTS-COM CHOICE - HEAT	04	2,109	63,973.4	480,839.38	.00	471,222.61	.00	471,222.61
32	11 11	GTS-COM CHOICE - NON-HEAT	08	136	705.1	5,470.19	.00	5,360.79	.00	5,360.79
32	11 11	GTS-COM CHOICE - HEAT&A/C	13	2	21.9	169.51	.00	166.12	.00	166.12
32	11 11	TOTAL COMMERCIAL		2,247	64,700.4	486,479.08	.00	1,370,847.40	.00	1,370,847.40
32	11 11	GTS-IND CHOICE - ALL	06	5	2,241.4	16,063.28	.00	15,742.02	.00	15,742.02
32	11 11	TOTAL		23,680	182,275.5	1,414,887.02	.00	1,386,589.42	.00	1,386,589.42

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,680 TIMES $ .200 = 4,736.00

********** COLUMBIA MCF CHARGE 182,275.5 TIMES $ .050 = 9,113.78

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STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

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COLUMBIA CHOICE PROGRAM - NOVEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 11 / 2011
GAS BILLING CYCLE: 10 / 2011

CD	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 11	GTS-RES CHOICE - HEAT	03	4,205	22,809.3	181,631.76	.00	177,999.14	.00	177,999.14
32	11 11	GTS-RES CHOICE - NON-HEAT	05	42	44.8	356.74	.00	349.59	.00	349.59
32	11 11	TOTAL RESIDENTIAL		4,247	22,854.1	181,988.50	.00	178,348.73	.00	178,348.73
32	11 11	GTS-COM CHOICE - HEAT	04	636	24,244.1	174,573.80	.00	171,082.30	.00	171,082.30
32	11 11	GTS-COM CHOICE - NON-HEAT	08	21	208.5	1,513.76	.00	1,483.48	.00	1,483.48
32	11 11	TOTAL COMMERCIAL		657	24,452.6	176,087.56	.00	350,914.51	.00	350,914.51
32	11 11	GTS-IND CHOICE - ALL	06	4	668.6	3,859.10	.00	3,781.92	.00	3,781.92
32	11 11	TOTAL		4,908	47,975.3	361,935.16	.00	354,696.43	.00	354,696.43

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,908 TIMES $ .200 = 981.60

********** COLUMBIA MCF CHARGE 47,975.3 TIMES $ .050 = 2,398.77

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RESPONDENT: JUDY M COOPER

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COLUMBIA CHOICE PROGRAM - NOVEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 11 / 2011
GAS BILLING CYCLE: 10 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 11	GTS-RES CHOICE - HEAT	03	1	11.2	65.64	.00	64.33	.00	64.33
32	11 11	TOTAL RESIDENTIAL		1	11.2	65.64	.00	64.33	.00	64.33
32	11 11	GTS-COM CHOICE - HEAT	04	74	5,087.7	29,831.52	.00	29,234.89	.00	29,234.89
32	11 11	TOTAL COMMERCIAL		74	5,087.7	29,831.52	.00	29,299.22	.00	29,299.22
32	11 11	GTS-IND CHOICE - ALL	06	1	127.5	747.28	.00	732.33	.00	732.33
32	11 11	TOTAL		76	5,226.4	30,644.44	.00	30,031.55	.00	30,031.55

********** # OF CUSTOMERS BILLED BY COLUMBIA 76 TIMES $ .200 = 15.20

********** COLUMBIA MCF CHARGE 5,226.4 TIMES $ .050 = 261.32

PSC CASE NO. 2013-00167
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 12/01/11

COLUMBIA CHOICE PROGRAM - NOVEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 11 / 2011
GAS BILLING CYCLE: 10 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 11	GTS-RES CHOICE - HEAT	03	1,661	8,066.5	54,891.65	.00	53,793.83	.00	53,793.83
32	11 11	GTS-RES CHOICE - NON-HEAT	05	29	24.2	164.73	.00	161.44	.00	161.44
32	11 11	TOTAL RESIDENTIAL		1,690	8,090.7	55,056.38	.00	53,955.27	.00	53,955.27
32	11 11	GTS-COM CHOICE - HEAT	04	1,151	26,026.3	177,105.66	.00	173,563.51	.00	173,563.51
32	11 11	GTS-COM CHOICE - NON-HEAT	08	22	700.3	4,766.95	.00	4,671.60	.00	4,671.60
32	11 11	TOTAL COMMERCIAL		1,173	26,726.6	181,872.61	.00	232,190.38	.00	232,190.38
32	11 11	GTS-IND CHOICE - ALL	06	4	112.4	765.11	.00	749.81	.00	749.81
32	11 11	TOTAL		2,867	34,929.7	237,694.10	.00	232,940.19	.00	232,940.19

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 2,867 TIMES $ .200 = 573.40

xxxxxxxxxx COLUMBIA MCF CHARGE 34,929.7 TIMES $ .050 = 1,746.49

RS5500MK
CURRENT DATE: 12/31/11

COLUMBIA CHOICE PROGRAM - DECEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 12 / 2011
GAS BILLING CYCLE: 11 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 11	GTS-RES CHOICE - HEAT	03	150	1,349.1	10,166.67	.00	9,963.33	.00	9,963.33
32	12 11	GTS-RES CHOICE - NON-HEAT	05	2	4.7	35.40	.00	34.69	.00	34.69
32	12 11	TOTAL RESIDENTIAL		152	1,353.8	10,202.07	.00	9,998.02	.00	9,998.02
32	12 11	GTS-COM CHOICE - HEAT	04	1	14.7	110.10	.00	107.90	.00	107.90
32	12 11	TOTAL COMMERCIAL		1	14.7	110.10	.00	10,105.92	.00	10,105.92
32	12 11	TOTAL		153	1,368.5	10,312.17	.00	10,105.92	.00	10,105.92

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 153 TIMES $ .200 = 30.60

xxxxxxxxxx COLUMBIA MCF CHARGE 1,368.5 TIMES $ .050 = 68.43

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RESPONDENT: JUDY M COOPER

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COLUMBIA CHOICE PROGRAM - DECEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : ~~COLUMBIA RETAIL ENERGY~~ IGS

DIS BILLING CYCLE: 12 / 2011
GAS BILLING CYCLE: 11 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 11	GTS-RES CHOICE - HEAT	03	21,331	202,079.1	1,596,467.50	.00	1,564,538.37	.00	1,564,538.37
32	12 11	GTS-RES CHOICE - NON-HEAT	05	243	691.0	5,504.16	.00	5,394.12	.00	5,394.12
32	12 11	TOTAL RESIDENTIAL		21,574	202,770.1	1,601,971.66	.00	1,569,932.49	.00	1,569,932.49
32	12 11	GTS-COM CHOICE - HEAT	04	2,104	112,172.8	838,607.23	.00	821,835.13	.00	821,835.13
32	12 11	GTS-COM CHOICE - NON-HEAT	08	137	750.0	5,581.96	.00	5,470.32	.00	5,470.32
32	12 11	GTS-COM CHOICE - HEAT&A/C	13	2	69.8	540.25	.00	529.45	.00	529.45
32	12 11	TOTAL COMMERCIAL		2,243	112,992.6	844,729.44	.00	2,397,767.39	.00	2,397,767.39
32	12 11	GTS-IND CHOICE - ALL	06	5	2,420.8	17,364.04	.00	17,016.76	.00	17,016.76
32	12 11	TOTAL		23,822	318,183.5	2,464,065.14	.00	2,414,784.15	.00	2,414,784.15

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,822 TIMES $ .200 = 4,764.40

********** COLUMBIA MCF CHARGE 318,183.5 TIMES $ .050 = 15,909.18

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 12/31/11

COLUMBIA CHOICE PROGRAM - DECEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 12 / 2011
GAS BILLING CYCLE: 11 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 11	GTS-RES CHOICE - HEAT	03	8	82.8	531.16	.00	520.53	.00	520.53
32	12 11	GTS-RES CHOICE - NON-HEAT	05	1	2.1	13.38	.00	13.11	.00	13.11
32	12 11	TOTAL RESIDENTIAL		9	84.9	544.54	.00	533.64	.00	533.64
32	12 11	GTS-COM CHOICE - HEAT	04	23	2,061.9	13,134.33	.00	12,871.64	.00	12,871.64
32	12 11	TOTAL COMMERCIAL		23	2,061.9	13,134.33	.00	13,405.28	.00	13,405.28
32	12 11	TOTAL		32	2,146.8	13,678.87	.00	13,405.28	.00	13,405.28

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 32 TIMES $ .200 = 6.40

xxxxxxxxxx COLUMBIA MCF CHARGE 2,146.8 TIMES $ .050 = 107.34

RS5500HK
CURRENT DATE: 12/31/11

COLUMBIA CHOICE PROGRAM - DECEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : NXENERGY

DIS BILLING CYCLE: 12 / 2011
GAS BILLING CYCLE: 11 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 11	GTS-RES CHOICE - HEAT	03	4,167	38,968.0	307,572.16	.00	301,420.74	.00	301,420.74
32	12 11	GTS-RES CHOICE - NON-HEAT	05	41	74.2	571.38	.00	559.96	.00	559.96
32	12 11	TOTAL RESIDENTIAL		4,208	39,042.2	308,143.54	.00	301,980.70	.00	301,980.70
32	12 11	GTS-COM CHOICE - HEAT	04	629	42,051.1	305,375.26	.00	299,267.80	.00	299,267.80
32	12 11	GTS-COM CHOICE - NON-HEAT	08	21	219.3	1,580.18	.00	1,548.57	.00	1,548.57
32	12 11	TOTAL COMMERCIAL		650	42,270.4	306,955.44	.00	602,797.07	.00	602,797.07
32	12 11	GTS-IND CHOICE - ALL	06	3	1,129.0	8,428.52	.00	8,259.95	.00	8,259.95
32	12 11	TOTAL		4,861	82,441.6	623,527.50	.00	611,057.02	.00	611,057.02

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,861 TIMES $ .200 = 972.20

********** COLUMBIA MCF CHARGE 82,441.6 TIMES $ .050 = 4,122.08

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 44 OF 145
RESPONDENT: JUDY M COOPER

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 45 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 12/31/11

COLUMBIA CHOICE PROGRAM - DECEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 12 / 2011
GAS BILLING CYCLE: 11 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 11	GTS-RES CHOICE - HEAT	03	1	12.6	68.54	.00	67.17	.00	67.17
32	12 11	TOTAL RESIDENTIAL		1	12.6	68.54	.00	67.17	.00	67.17
32	12 11	GTS-COM CHOICE - HEAT	04	74	8,511.2	46,464.87	.00	45,535.57	.00	45,535.57
32	12 11	TOTAL COMMERCIAL		74	8,511.2	46,464.87	.00	45,602.74	.00	45,602.74
32	12 11	GTS-IND CHOICE - ALL	06	1	323.3	1,758.75	.00	1,723.58	.00	1,723.58
32	12 11	TOTAL		76	8,847.1	48,292.16	.00	47,326.32	.00	47,326.32

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 76 TIMES $ .200 = 15.20

xxxxxxxxxx COLUMBIA MCF CHARGE 8,847.1 TIMES $ .050 = 442.36

RS5500HK
CURRENT DATE: 12/31/11

COLUMBIA CHOICE PROGRAM - DECEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 12 / 2011
GAS BILLING CYCLE: 11 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 11	GTS-RES CHOICE - HEAT	03	1,646	13,914.0	90,059.24	.00	88,258.31	.25-	88,258.31
32	12 11	GTS-RES CHOICE - NON-HEAT	05	30	35.8	231.76	.00	227.13	.00	227.13
32	12 11	TOTAL RESIDENTIAL		1,676	13,949.8	90,291.00	.00	88,485.44	.25-	88,485.44
32	12 11	GTS-COM CHOICE - HEAT	04	1,147	43,516.9	281,948.48	.00	276,309.54	.00	276,309.54
32	12 11	GTS-COM CHOICE - NON-HEAT	08	22	829.1	5,367.61	.00	5,260.25	.00	5,260.25
32	12 11	TOTAL COMMERCIAL		1,169	44,346.0	287,316.09	.00	370,055.23	.25-	370,055.23
32	12 11	GTS-IND CHOICE - ALL	06	4	144.8	954.08	.00	934.99	.00	934.99
32	12 11	TOTAL		2,849	58,440.6	378,561.17	.00	370,990.22	.25-	370,990.22

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,849 TIMES $ .200 = 569.80

********** COLUMBIA MCF CHARGE 58,440.6 TIMES $ .050 = 2,922.03

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 46 OF 145
RESPONDENT: JUDY M COOPER

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 47 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 12/31/11

COLUMBIA CHOICE PROGRAM - DECEMBER 2011
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MARKETER NAME NOT FOUND

DIS BILLING CYCLE: 12 / 2011
GAS BILLING CYCLE: 11 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 11	TOTAL RESIDENTIAL			.0	.00	.00	.00	.00	.00
32	12 11	GTS-COM CHOICE - HEAT	04	1	.0	2,016.51-	.00	.00	2,016.51-	.00
32	12 11	TOTAL COMMERCIAL		1	.0	2,016.51-	.00	.00	2,016.51-	.00
32	12 11	TOTAL		1	.0	2,016.51-	.00	.00	2,016.51-	.00

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 0 TIMES $ .200 = .00

xxxxxxxxxx COLUMBIA MCF CHARGE .0 TIMES $ .050 = .00

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 48 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 02/01/12

COLUMBIA CHOICE PROGRAM - JANUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 01 / 2012
GAS BILLING CYCLE: 12 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 12	GTS-RES CHOICE - HEAT	03	148	2,009.2	14,881.48	.00	14,583.85	.00	14,583.85
32	01 12	GTS-RES CHOICE - NON-HEAT	05	2	6.4	49.44	.00	48.45	.00	48.45
32	01 12	TOTAL RESIDENTIAL		150	2,015.6	14,930.92	.00	14,632.30	.00	14,632.30
32	01 12	GTS-COM CHOICE - HEAT	04	1	20.0	149.80	.00	146.80	.00	146.80
32	01 12	TOTAL COMMERCIAL		1	20.0	149.80	.00	14,779.10	.00	14,779.10
32	01 12	TOTAL		151	2,035.6	15,080.72	.00	14,779.10	.00	14,779.10

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 151 TIMES $ .200 = 30.20

xxxxxxxxxx COLUMBIA MCF CHARGE 2,035.6 TIMES $ .050 = 101.78

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 49 OF 145
RESPONDENT: JUDY M COOPER

RS5500HK
CURRENT DATE: 02/01/12

COLUMBIA CHOICE PROGRAM - JANUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

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DIS BILLING CYCLE: 01 / 2012
GAS BILLING CYCLE: 12 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 12	GTS-RES CHOICE - HEAT	03	21,388	298,134.1	2,298,996.46	.00	2,253,016.53	.00	2,253,016.53
32	01 12	GTS-RES CHOICE - NON-HEAT	05	247	1,025.7	8,022.87	.00	7,862.45	.00	7,862.45
32	01 12	TOTAL RESIDENTIAL		21,635	299,159.8	2,307,019.33	.00	2,260,878.98	.00	2,260,878.98
32	01 12	GTS-COM CHOICE - HEAT	04	2,075	155,478.6	1,144,547.49	.00	1,121,656.60	.00	1,121,656.60
32	01 12	GTS-COM CHOICE - NON-HEAT	08	137	685.9	5,057.33	.00	4,956.18	.00	4,956.18
32	01 12	GTS-COM CHOICE - HEAT&A/C	13	2	103.8	777.46	.00	761.91	.00	761.91
32	01 12	TOTAL COMMERCIAL		2,214	156,268.3	1,150,382.28	.00	3,388,253.67	.00	3,388,253.67
32	01 12	GTS-IND CHOICE - ALL	06	5	2,050.3	14,793.00	.00	14,497.15	.00	14,497.15
32	01 12	TOTAL		23,854	457,478.4	3,472,194.61	.00	3,402,750.82	.00	3,402,750.82

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,854 TIMES $ .200 = 4,770.80

********** COLUMBIA MCF CHARGE 457,478.4 TIMES $ .050 = 22,873.92

RS5500HK
CURRENT DATE: 02/01/12

COLUMBIA CHOICE PROGRAM - JANUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

OIS BILLING CYCLE: 01 / 2012
GAS BILLING CYCLE: 12 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 12	GTS-RES CHOICE - HEAT	03	4,131	56,863.7	445,406.62	.00	436,498.51	.00	436,498.51
32	01 12	GTS-RES CHOICE - NON-HEAT	05	41	93.6	716.75	.00	702.43	.00	702.43
32	01 12	TOTAL RESIDENTIAL		4,172	56,957.3	446,123.37	.00	437,200.94	.00	437,200.94
32	01 12	GTS-COM CHOICE - HEAT	04	687	75,114.3	531,444.45	.00	520,815.57	.00	520,815.57
32	01 12	GTS-COM CHOICE - NON-HEAT	08	20	209.6	1,518.09	.00	1,487.73	.00	1,487.73
32	01 12	TOTAL COMMERCIAL		707	75,323.9	532,962.54	.00	959,504.24	.00	959,504.24
32	01 12	GTS-IND CHOICE - ALL	06	5	6,471.1	40,672.95	.00	39,859.47	.00	39,859.47
32	01 12	TOTAL		4,882	138,752.3	1,019,758.84	.00	999,363.71	.00	999,363.71

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,882 TIMES $ .200 = 976.40

********** COLUMBIA MCF CHARGE 138,752.3 TIMES $ .050 = 6,937.62

RS5500NK
CURRENT DATE: 02/01/12

COLUMBIA CHOICE PROGRAM - JANUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 01 / 2012
GAS BILLING CYCLE: 12 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 12	GTS-RES CHOICE - HEAT	03	1	17.1	89.26	.00	87.47	.00	87.47
32	01 12	TOTAL RESIDENTIAL		1	17.1	89.26	.00	87.47	.00	87.47
32	01 12	GTS-COM CHOICE - HEAT	04	59	13,501.0	72,041.00	.00	70,600.18	.00	70,600.18
32	01 12	TOTAL COMMERCIAL		59	13,501.0	72,041.00	.00	70,687.65	.00	70,687.65
32	01 12	GTS-IND CHOICE - ALL	06	1	261.9	1,367.12	.00	1,339.78	.00	1,339.78
32	01 12	TOTAL		61	13,780.0	73,497.38	.00	72,027.43	.00	72,027.43

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 13,780.0 TIMES $ .050 = 689.00

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 52 OF 145
RESPONDENT: JUDY M COOPER

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 53 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 02/01/12

COLUMBIA CHOICE PROGRAM - JANUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 01 / 2012
GAS BILLING CYCLE: 12 / 2011

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 12	GTS-RES CHOICE - HEAT	03	1,627	20,352.8	108,036.34	.00	105,876.21	.54-	105,876.21
32	01 12	GTS-RES CHOICE - NON-HEAT	05	28	43.2	229.40	.00	224.81	.00	224.81
32	01 12	TOTAL RESIDENTIAL		1,655	20,396.0	108,265.74	.00	106,101.02	.54-	106,101.02
32	01 12	GTS-COM CHOICE - HEAT	04	1,118	58,641.9	312,574.41	.00	306,322.90	.00	306,322.90
32	01 12	GTS-COM CHOICE - NON-HEAT	08	21	578.7	3,074.19	.00	3,012.70	.00	3,012.70
32	01 12	TOTAL COMMERCIAL		1,139	59,220.6	315,648.60	.00	415,436.62	.54-	415,436.62
32	01 12	GTS-IND CHOICE - ALL	06	4	133.4	736.30	.00	721.57	.00	721.57
32	01 12	TOTAL		2,798	79,750.0	424,650.64	.00	416,158.19	.54-	416,158.19

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,798 TIMES $ .200 = 559.60

********** COLUMBIA MCF CHARGE 79,750.0 TIMES $ .050 = 3,987.50

RS550GHK
CURRENT DATE: 03/01/12

COLUMBIA CHOICE PROGRAM - FEBRUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

OIS BILLING CYCLE: 02 / 2012
GAS BILLING CYCLE: 01 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	MGN GUARANTEED	TOTAL MKT PAYMENT
32	02 12	GTS-RES CHOICE - HEAT	03	147	1,776.0	13,215.00	.00	12,950.71	.00	12,950.71
32	02 12	GTS-RES CHOICE - NON-HEAT	05	2	5.2	39.72	.00	38.93	.00	38.93
32	02 12	TOTAL RESIDENTIAL		149	1,781.2	13,254.72	.00	12,989.64	.00	12,989.64
32	02 12	GTS-COM CHOICE - HEAT	04	1	15.4	107.65	.00	105.50	.00	105.50
32	02 12	TOTAL COMMERCIAL		1	15.4	107.65	.00	13,095.14	.00	13,095.14
32	02 12	TOTAL		150	1,796.6	13,362.37	.00	13,095.14	.00	13,095.14

********** # OF CUSTOMERS BILLED BY COLUMBIA 150 TIMES $ .200 = 30.00

********** COLUMBIA MCF CHARGE 1,796.6 TIMES $ .050 = 89.83

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 55 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 03/01/12

COLUMBIA CHOICE PROGRAM - FEBRUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

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DIS BILLING CYCLE: 02 / 2012
GAS BILLING CYCLE: 01 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 12	GTS-RES CHOICE - HEAT	03	21,314	274,059.6	2,052,753.04	.00	2,011,698.05	.00	2,011,698.05
32	02 12	GTS-RES CHOICE - NON-HEAT	05	247	968.1	7,404.97	.00	7,256.84	.00	7,256.84
32	02 12	TOTAL RESIDENTIAL		21,561	275,027.7	2,060,158.01	.00	2,018,954.89	.00	2,018,954.89
32	02 12	GTS-COM CHOICE - HEAT	04	2,067	143,489.1	1,028,719.74	.00	1,008,145.63	.00	1,008,145.63
32	02 12	GTS-COM CHOICE - NON-HEAT	09	137	640.5	4,532.71	.00	4,442.13	.00	4,442.13
32	02 12	GTS-COM CHOICE - HEAT&A/C	13	2	114.6	823.98	.00	807.51	.00	807.51
32	02 12	TOTAL COMMERCIAL		2,206	144,244.2	1,034,076.43	.00	3,032,350.16	.00	3,032,350.16
32	02 12	GTS-IND CHOICE - ALL	06	5	3,064.5	21,728.93	.00	21,294.34	.00	21,294.34
32	02 12	TOTAL		23,772	422,336.4	3,115,963.37	.00	3,053,644.50	.00	3,053,644.50

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,772 TIMES $ .200 = 4,754.40

********** COLUMBIA MCF CHARGE 422,336.4 TIMES $ .050 = 21,116.82

RS5500MK
CURRENT DATE: 03/01/12

COLUMBIA CHOICE PROGRAM - FEBRUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 02 / 2012
GAS BILLING CYCLE: 01 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 12	GTS-RES CHOICE - HEAT	03	12	195.9	1,245.54	.00	1,220.63	.00	1,220.63
32	02 12	GTS-RES CHOICE - NON-HEAT	05	1	2.4	15.29	.00	14.98	.00	14.98
32	02 12	TOTAL RESIDENTIAL		13	198.3	1,260.83	.00	1,235.61	.00	1,235.61
32	02 12	GTS-COM CHOICE - HEAT	04	35	5,298.5	32,888.53	.00	32,230.78	.00	32,230.78
32	02 12	GTS-COM CHOICE - NON-HEAT	08	1	45.5	289.84	.00	284.04	.00	284.04
32	02 12	TOTAL COMMERCIAL		36	5,344.0	33,178.37	.00	33,750.43	.00	33,750.43
32	02 12	TOTAL		49	5,542.3	34,439.20	.00	33,750.43	.00	33,750.43

********** # OF CUSTOMERS BILLED BY COLUMBIA 49 TIMES $ .200 = 9.80

********** COLUMBIA MCF CHARGE 5,542.3 TIMES $ .050 = 277.12

RS550DMK
CURRENT DATE: 03/01/12

COLUMBIA CHOICE PROGRAM - FEBRUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 02 / 2012
GAS BILLING CYCLE: 01 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 12	GTS-RES CHOICE - HEAT	03	4,102	52,286.6	394,390.61	.00	386,502.87	.00	386,502.87
32	02 12	GTS-RES CHOICE - NON-HEAT	05	41	86.1	635.14	.00	622.43	.00	622.43
32	02 12	TOTAL RESIDENTIAL		4,143	52,372.7	395,025.75	.00	387,125.30	.00	387,125.30
32	02 12	GTS-COM CHOICE - HEAT	04	675	71,946.0	480,242.81	.00	470,638.08	.00	470,638.08
32	02 12	GTS-COM CHOICE - NON-HEAT	08	20	146.8	1,061.57	.00	1,040.34	.00	1,040.34
32	02 12	TOTAL COMMERCIAL		695	72,092.8	481,304.38	.00	858,803.72	.00	858,803.72
32	02 12	GTS-IND CHOICE - ALL	06	3	3,460.8	20,351.94	.00	19,944.90	.00	19,944.90
32	02 12	TOTAL		4,841	127,926.3	896,682.07	.00	878,748.62	.00	878,748.62

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,841 TIMES $ .200 = 968.20

********** COLUMBIA MCF CHARGE 127,926.3 TIMES $ .050 = 6,396.32

RS5500MK
CURRENT DATE: 03/01/12

COLUMBIA CHOICE PROGRAM - FEBRUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 02 / 2012
GAS BILLING CYCLE: 01 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 12	GTS-RES CHOICE - HEAT	03	1	14.5	65.69	.00	64.38	.00	64.38
32	02 12	TOTAL RESIDENTIAL		1	14.5	65.69	.00	64.38	.00	64.38
32	02 12	GTS-COM CHOICE - HEAT	04.	59	12,648.6	61,322.19	.00	60,095.75	.00	60,095.75
32	02 12	TOTAL COMMERCIAL		59	12,648.6	61,322.19	.00	60,160.13	.00	60,160.13
32	02 12	GTS-IND CHOICE - ALL	06	1	274.9	1,245.30	.00	1,220.39	.00	1,220.39
32	02 12	TOTAL		61	12,938.0	62,633.18	.00	61,380.52	.00	61,380.52

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 12,938.0 TIMES $ .050 = 646.90

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS550MK
CURRENT DATE: 03/01/12

COLUMBIA CHOICE PROGRAM - FEBRUARY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 02 / 2012
GAS BILLING CYCLE: 01 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 12	GTS-RES CHOICE - HEAT	03	1,614	18,800.6	111,556.06	.00	109,324.99	.00	109,324.99
32	02 12	GTS-RES CHOICE - NON-HEAT	85	27	38.5	228.45	.00	223.89	.00	223.89
32	02 12	TOTAL RESIDENTIAL		1,641	18,839.1	111,784.51	.00	109,548.88	.00	109,548.88
32	02 12	GTS-COM CHOICE - HEAT	04	1,110	54,058.3	320,491.06	.00	314,081.27	.00	314,081.27
32	02 12	GTS-COM CHOICE - NON-HEAT	08	20	554.2	3,288.60	.00	3,222.82	.00	3,222.82
32	02 12	TOTAL COMMERCIAL		1,130	54,612.5	323,779.66	.00	426,852.97	.00	426,852.97
32	02 12	GTS-IND CHOICE - ALL	06	4	120.7	699.38	.00	685.39	.00	685.39
32	02 12	TOTAL		2,775	73,572.3	436,263.55	.00	427,538.36	.00	427,538.36

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,775 TIMES $ .200 = 555.00

********** COLUMBIA MCF CHARGE 73,572.3 TIMES $ .050 = 3,678.62

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 03/31/12

COLUMBIA CHOICE PROGRAM - MARCH 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 03 / 2012
GAS BILLING CYCLE: 02 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 12	GTS-RES CHOICE - HEAT	03	144	1,242.6	9,297.02	.00	9,111.07	.00	9,111.07
32	03 12	GTS-RES CHOICE - NON-HEAT	05	2	4.4	32.10	.00	31.46	.00	31.46
32	03 12	TOTAL RESIDENTIAL		146	1,247.0	9,329.12	.00	9,142.53	.00	9,142.53
32	03 12	GTS-COM CHOICE - HEAT	04	1	7.6	63.00	.00	61.74	.00	61.74
32	03 12	TOTAL COMMERCIAL		1	7.6	63.00	.00	9,204.27	.00	9,204.27
32	03 12	TOTAL		147	1,254.6	9,392.12	.00	9,204.27	.00	9,204.27

********** # OF CUSTOMERS BILLED BY COLUMBIA 147 TIMES $ .200 = 29.40

********** COLUMBIA MCF CHARGE 1,254.6 TIMES $ .050 = 62.73

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RESPONDENT: JUDY M COOPER

RS55Q0HK
CURRENT DATE: 03/31/12

COLUMBIA CHOICE PROGRAM - MARCH 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

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DIS BILLING CYCLE: 03 / 2012
GAS BILLING CYCLE: 02 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 12	GTS-RES CHOICE - HEAT	03	21,339	198,717.7	1,487,097.32	.00	1,457,355.43	.00	1,457,355.43
32	03 12	GTS-RES CHOICE - NON-HEAT	05	252	761.5	5,809.79	.00	5,693.63	.00	5,693.63
32	03 12	TOTAL RESIDENTIAL		21,591	199,479.2	1,492,907.11	.00	1,463,049.06	.00	1,463,049.06
32	03 12	GTS-COM CHOICE - HEAT	04	2,063	112,219.3	791,571.74	.00	775,740.50	.00	775,740.50
32	03 12	GTS-COM CHOICE - NON-HEAT	08	134	616.5	4,310.28	.00	4,224.15	.00	4,224.15
32	03 12	GTS-COM CHOICE - HEAT&A/C	13	2	68.9	495.39	.00	485.48	.00	485.48
32	03 12	TOTAL COMMERCIAL		2,199	112,904.7	796,377.41	.00	2,243,499.19	.00	2,243,499.19
32	03 12	GTS-IND CHOICE - ALL	06	5	2,566.9	18,215.57	.00	17,851.06	.00	17,851.06
32	03 12	TOTAL		23,795	314,950.8	2,307,499.89	.00	2,261,350.25	.00	2,261,350.25

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,795 TIMES $ .200 = 4,759.00

********** COLUMBIA MCF CHARGE 314,950.8 TIMES $ .050 = 15,747.54

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 03/31/12

COLUMBIA CHOICE PROGRAM - MARCH 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 03 / 2012
GAS BILLING CYCLE: 02 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 12	GTS-RES CHOICE - HEAT	03	15	166.9	1,023.60	.00	1,003.12	.00	1,003.12
32	03 12	GTS-RES CHOICE - NON-HEAT	05	1	1.4	8.92	.00	8.74	.00	8.74
32	03 12	TOTAL RESIDENTIAL		16	168.3	1,032.52	.00	1,011.86	.00	1,011.86
32	03 12	GTS-COM CHOICE - HEAT	04	38	4,515.1	26,957.68	.00	26,418.68	.00	26,418.68
32	03 12	GTS-COM CHOICE - NON-HEAT	08	1	45.0	286.65	.00	280.92	.00	280.92
32	03 12	TOTAL COMMERCIAL		39	4,560.1	27,244.53	.00	27,711.46	.00	27,711.46
32	03 12	TOTAL		55	4,728.4	28,277.05	.00	27,711.46	.00	27,711.46

********** # OF CUSTOMERS BILLED BY COLUMBIA 55 TIMES $ .200 = 11.00

********** COLUMBIA MCF CHARGE 4,728.4 TIMES $ .050 = 236.42

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RESPONDENT: JUDY M COOPER

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CURRENT DATE: 03/31/12

COLUMBIA CHOICE PROGRAM - MARCH 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 03 / 2012
GAS BILLING CYCLE: 02 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 12	GTS-RES CHOICE - HEAT	03	4,068	36,914.5	277,387.48	.00	271,839.83	.00	271,839.83
32	03 12	GTS-RES CHOICE - NON-HEAT	05	41	66.2	482.74	.00	473.09	.00	473.09
32	03 12	TOTAL RESIDENTIAL		4,109	36,980.7	277,870.22	.00	272,312.92	.00	272,312.92
32	03 12	GTS-COM CHOICE - HEAT	04	666	50,272.3	327,085.79	.00	320,544.16	.00	320,544.16
32	03 12	GTS-COM CHOICE - NON-HEAT	08	20	172.8	1,233.14	.00	1,208.48	.00	1,208.48
32	03 12	TOTAL COMMERCIAL		686	50,445.1	328,318.93	.00	594,065.56	.00	594,065.56
32	03 12	GTS-IND CHOICE - ALL	06	3	2,585.3	15,149.01	.00	14,846.03	.00	14,846.03
32	03 12	TOTAL		4,798	90,011.1	621,338.16	.00	608,911.59	.00	608,911.59

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,798 TIMES $ .200 = 959.60

********** COLUMBIA MCF CHARGE 90,011.1 TIMES $ .050 = 4,500.56

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COLUMBIA CHOICE PROGRAM - MARCH 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 03 / 2012
GAS BILLING CYCLE: 02 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 12	GTS-RES CHOICE - HEAT	03	1	14.1	65.14	.00	63.84	.00	63.84
32	03 12	TOTAL RESIDENTIAL		1	14.1	65.14	.00	63.84	.00	63.84
32	03 12	GTS-COM CHOICE - HEAT	04	59	8,814.1	42,176.45	.00	41,332.92	.00	41,332.92
32	03 12	TOTAL COMMERCIAL		59	8,814.1	42,176.45	.00	41,396.76	.00	41,396.76
32	03 12	GTS-IND CHOICE - ALL	06	1	112.5	519.75	.00	509.36	.00	509.36
32	03 12	TOTAL		61	8,940.7	42,761.34	.00	41,906.12	.00	41,906.12

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 8,940.7 TIMES $ .050 = 447.04

RS5500MK
CURRENT DATE: 03/31/12

COLUMBIA CHOICE PROGRAM - MARCH 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 03 / 2012
GAS BILLING CYCLE: 02 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 12	GTS-RES CHOICE - HEAT	03	1,597	13,577.2	75,020.54	.00	73,520.10	.00	73,520.10
32	03 12	GTS-RES CHOICE - NON-HEAT	05	27	34.5	190.71	.00	186.89	.00	186.89
32	03 12	TOTAL RESIDENTIAL		1,624	13,611.7	75,211.25	.00	73,706.99	.00	73,706.99
32	03 12	GTS-COM CHOICE - HEAT	04	1,096	39,079.3	216,107.17	.00	211,785.27	.00	211,785.27
32	03 12	GTS-COM CHOICE - NON-HEAT	08	20	512.4	2,832.54	.00	2,775.91	.00	2,775.91
32	03 12	TOTAL COMMERCIAL		1,116	39,591.7	218,939.71	.00	288,268.17	.00	288,268.17
32	03 12	GTS-IND CHOICE - ALL	06	4	94.2	531.70	.00	521.07	.00	521.07
32	03 12	TOTAL		2,744	53,297.6	294,682.66	.00	288,789.24	.00	288,789.24

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,744 TIMES $ .200 = 548.80

********** COLUMBIA MCF CHARGE 53,297.6 TIMES $ .050 = 2,664.88

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RS5500MK
CURRENT DATE: 05/01/12

COLUMBIA CHOICE PROGRAM - APRIL 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 04 / 2012
GAS BILLING CYCLE: 03 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 12	GTS-RES CHOICE - HEAT	03	139	488.7	3,836.71	.00	3,759.97	.00	3,759.97
32	04 12	GTS-RES CHOICE - NON-HEAT	05	1	3.1	21.69	.00	21.25	.00	21.25
32	04 12	TOTAL RESIDENTIAL		140	491.8	3,858.40	.00	3,781.22	.00	3,781.22
32	04 12	GTS-COM CHOICE - HEAT	04	1	4.3	35.65	.00	34.94	.00	34.94
32	04 12	TOTAL COMMERCIAL		1	4.3	35.65	.00	3,816.16	.00	3,816.16
32	04 12	TOTAL		141	496.1	3,894.05	.00	3,816.16	.00	3,816.16

********** # OF CUSTOMERS BILLED BY COLUMBIA 141 TIMES $ .200 = 28.20

********** COLUMBIA MCF CHARGE 496.1 TIMES $ .050 = 24.81

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COLUMBIA CHOICE PROGRAM - APRIL 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

DIS BILLING CYCLE: 04 / 2012
GAS BILLING CYCLE: 03 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 12	GTS-RES CHOICE - HEAT	03	21,192	77,484.1	579,370.27	.00	567,783.35	.37-	567,783.35
32	04 12	GTS-RES CHOICE - NON-HEAT	05	249	370.3	2,833.97	.00	2,777.33	.00	2,777.33
32	04 12	TOTAL RESIDENTIAL		21,441	77,854.4	582,204.24	.00	570,560.68	.37-	570,560.68
32	04 12	GTS-COM CHOICE - HEAT	04	2,051	52,575.2	361,290.39	.00	354,064.93	.00	354,064.93
32	04 12	GTS-COM CHOICE - NON-HEAT	08	134	560.8	3,891.20	.00	3,813.43	.00	3,813.43
32	04 12	GTS-COM CHOICE - HEAT&A/C	13	2	21.9	157.46	.00	154.31	.00	154.31
32	04 12	TOTAL COMMERCIAL		2,187	53,157.9	365,339.05	.00	928,593.35	.37-	928,593.35
32	04 12	GTS-IND CHOICE - ALL	06	5	2,288.3	15,151.78	.00	14,848.75	.00	14,848.75
32	04 12	TOTAL		23,633	133,300.6	962,695.07	.00	943,442.10	.37-	943,442.10

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,633 TIMES $ .200 = 4,726.60

********** COLUMBIA MCF CHARGE 133,300.6 TIMES $ .050 = 6,665.03

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RS550UMK
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COLUMBIA CHOICE PROGRAM - APRIL 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 04 / 2012
GAS BILLING CYCLE: 03 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 12	GTS-RES CHOICE - HEAT	03	16	66.0	375.23	.00	367.72	.00	367.72
32	04 12	GTS-RES CHOICE - NON-HEAT	05	1	.4	2.33	.00	2.28	.00	2.28
32	04 12	TOTAL RESIDENTIAL		17	66.4	377.56	.00	370.00	.00	370.00
32	04 12	GTS-COM CHOICE - HEAT	04	45	2,041.0	11,801.56	.00	11,565.54	.00	11,565.54
32	04 12	GTS-COM CHOICE - NON-HEAT	08	1	54.6	317.77	.00	311.41	.00	311.41
32	04 12	TOTAL COMMERCIAL		46	2,095.6	12,119.33	.00	12,246.95	.00	12,246.95
32	04 12	TOTAL		63	2,162.0	12,496.89	.00	12,246.95	.00	12,246.95

********* # OF CUSTOMERS BILLED BY COLUMBIA 63 TIMES $ .200 = 12.60

********* COLUMBIA MCF CHARGE 2,162.0 TIMES $ .050 = 108.10

RS5500MK
CURRENT DATE: 05/01/12

COLUMBIA CHOICE PROGRAM - APRIL 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 04 / 2012
GAS BILLING CYCLE: 03 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 12	GTS-RES CHOICE - HEAT	03	4,026	14,735.9	106,098.97	.00	103,977.06	.00	103,977.06
32	04 12	GTS-RES CHOICE - NON-HEAT	05	41	40.4	282.33	.00	276.67	.00	276.67
32	04 12	TOTAL RESIDENTIAL		4,067	14,776.3	106,381.30	.00	104,253.73	.00	104,253.73
32	04 12	GTS-COM CHOICE - HEAT	04	655	21,953.4	140,177.99	.00	137,374.49	.00	137,374.49
32	04 12	GTS-COM CHOICE - NON-HEAT	08	20	195.6	1,365.07	.00	1,337.77	.00	1,337.77
32	04 12	TOTAL COMMERCIAL		675	22,149.0	141,543.06	.00	242,965.99	.00	242,965.99
32	04 12	GTS-IND CHOICE - ALL	06	3	610.5	3,576.43	.00	3,504.90	.00	3,504.90
32	04 12	TOTAL		4,745	37,535.8	251,500.79	.00	246,470.89	.00	246,470.89

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,745 TIMES $ .200 = 949.00

********** COLUMBIA MCF CHARGE 37,535.8 TIMES $ .050 = 1,876.79

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COLUMBIA CHOICE PROGRAM - APRIL 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 04 / 2012
GAS BILLING CYCLE: 03 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 12	GTS-RES CHOICE - HEAT	03	1	12.9	58.18	.00	57.02	.00	57.02
32	04 12	TOTAL RESIDENTIAL		1	12.9	58.18	.00	57.02	.00	57.02
32	04 12	GTS-COM CHOICE - HEAT	04	59	3,268.8	15,166.43	.00	14,863.11	.00	14,863.11
32	04 12	TOTAL COMMERCIAL		59	3,268.8	15,166.43	.00	14,920.13	.00	14,920.13
32	04 12	GTS-IND CHOICE - ALL	06	1	84.3	380.19	.00	372.59	.00	372.59
32	04 12	TOTAL		61	3,366.0	15,604.80	.00	15,292.72	.00	15,292.72

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 3,366.0 TIMES $ .050 = 168.30

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RS550UHK
CURRENT DATE: 05/01/12

COLUMBIA CHOICE PROGRAM - APRIL 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 04 / 2012
GAS BILLING CYCLE: 03 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	04 12	GTS-RES CHOICE - HEAT	03	1,592	5,525.7	29,028.51	.00	28,447.91	.00	28,447.91
32	04 12	GTS-RES CHOICE - NON-HEAT	05	27	13.2	69.23	.00	67.85	.00	67.85
32	04 12	TOTAL RESIDENTIAL		1,619	5,538.9	29,097.74	.00	28,515.76	.00	28,515.76
32	04 12	GTS-COM CHOICE - HEAT	04	1,089	19,663.9	103,153.61	.00	101,090.80	.00	101,090.80
32	04 12	GTS-COM CHOICE - NON-HEAT	08	20	483.2	2,535.75	.00	2,485.04	.00	2,485.04
32	04 12	TOTAL COMMERCIAL		1,109	20,147.1	105,689.36	.00	132,091.60	.00	132,091.60
32	04 12	GTS-IND CHOICE - ALL	06	3	40.6	216.94	.00	212.60	.00	212.60
32	04 12	TOTAL		2,731	25,726.6	135,004.04	.00	132,304.20	.00	132,304.20

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,731 TIMES $ .200 = 546.20

********** COLUMBIA MCF CHARGE 25,726.6 TIMES $ .050 = 1,286.33

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RS5500MK
CURRENT DATE: 06/01/12

COLUMBIA CHOICE PROGRAM - MAY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 05 / 2012
GAS BILLING CYCLE: 04 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 12	GTS-RES CHOICE - HEAT	03	136	337.3	2,508.68	.00	2,458.51	.00	2,458.51
32	05 12	GTS-RES CHOICE - NON-HEAT	05	1	3.0	20.58	.00	20.17	.00	20.17
32	05 12	TOTAL RESIDENTIAL		137	340.3	2,529.26	.00	2,478.68	.00	2,478.68
32	05 12	GTS-COM CHOICE - HEAT	04	1	2.8	22.37	.00	21.92	.00	21.92
32	05 12	TOTAL COMMERCIAL		1	2.8	22.37	.00	2,500.60	.00	2,500.60
32	05 12	TOTAL		138	343.1	2,551.63	.00	2,500.60	.00	2,500.60

********** # OF CUSTOMERS BILLED BY COLUMBIA 138 TIMES $ .200 = 27.60

********** COLUMBIA MCF CHARGE 343.1 TIMES $ .050 = 17.16

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 06/01/12

COLUMBIA CHOICE PROGRAM - MAY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

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DIS BILLING CYCLE: 05 / 2012
GAS BILLING CYCLE: 04 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 12	GTS-RES CHOICE - HEAT	03	21,042	58,156.6	426,359.63	.00	417,833.04	.60-	417,833.04
32	05 12	GTS-RES CHOICE - NON-HEAT	05	249	352.5	2,687.28	.00	2,633.56	.00	2,633.56
32	05 12	TOTAL RESIDENTIAL		21,291	58,509.1	429,046.91	.00	420,466.60	.60-	420,466.60
32	05 12	GTS-COM CHOICE - HEAT	04	2,035	38,468.8	265,542.13	.00	260,231.53	.00	260,231.53
32	05 12	GTS-COM CHOICE - NON-HEAT	08	134	670.4	4,517.59	.00	4,427.27	.00	4,427.27
32	05 12	GTS-COM CHOICE - HEAT&A/C	13	2	12.7	88.77	.00	87.00	.00	87.00
32	05 12	TOTAL COMMERCIAL		2,169	39,151.9	270,148.49	.00	685,212.40	.60-	685,212.40
32	05 12	GTS-IND CHOICE - ALL	06	5	2,500.2	16,497.20	.00	16,167.26	.00	16,167.26
32	05 12	TOTAL		23,465	100,161.2	715,692.60	.00	701,379.66	.60-	701,379.66

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,465 TIMES $ .200 = 4,693.00

********** COLUMBIA MCF CHARGE 100,161.2 TIMES $ .050 = 5,008.06

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STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 06/01/12

COLUMBIA CHOICE PROGRAM - MAY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 05 / 2012
GAS BILLING CYCLE: 04 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 12	GTS-RES CHOICE - HEAT	03	21	54.3	301.83	.00	295.78	.00	295.78
32	05 12	GTS-RES CHOICE - NON-HEAT	05	1	.1	.58	.00	.57	.00	.57
32	05 12	TOTAL RESIDENTIAL		22	54.4	302.41	.00	296.35	.00	296.35
32	05 12	GTS-COM CHOICE - HEAT	04	53	1,409.6	7,746.67	.00	7,591.94	.00	7,591.94
32	05 12	GTS-COM CHOICE - NON-HEAT	08	1	50.2	292.16	.00	286.32	.00	286.32
32	05 12	TOTAL COMMERCIAL		54	1,459.8	8,039.03	.00	8,174.61	.00	8,174.61
32	05 12	TOTAL		76	1,514.2	8,341.44	.00	8,174.61	.00	8,174.61

********** # OF CUSTOMERS BILLED BY COLUMBIA 76 TIMES $ .200 = 15.20

********** COLUMBIA MCF CHARGE 1,514.2 TIMES $ .050 = 75.71

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 06/01/12

COLUMBIA CHOICE PROGRAM - MAY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : NXENERGY

DIS BILLING CYCLE: 05 / 2012
GAS BILLING CYCLE: 04 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 12	GTS-RES CHOICE - HEAT	03	4,056	11,100.4	73,231.61	.00	71,766.90	.00	71,766.90
32	05 12	GTS-RES CHOICE - NON-HEAT	05	41	39.3	256.48	.00	251.34	.00	251.34
32	05 12	TOTAL RESIDENTIAL		4,097	11,139.7	73,488.09	.00	72,018.24	.00	72,018.24
32	05 12	GTS-COM CHOICE - HEAT	04	761	20,624.2	120,336.31	.00	117,929.66	.00	117,929.66
32	05 12	GTS-COM CHOICE - NON-HEAT	08	23	317.7	1,993.70	.00	1,953.83	.00	1,953.83
32	05 12	TOTAL COMMERCIAL		784	20,941.9	122,330.01	.00	191,901.73	.00	191,901.73
32	05 12	GTS-IND CHOICE - ALL	06	3	432.9	2,532.47	.00	2,481.82	.00	2,481.82
32	05 12	TOTAL		4,884	32,514.5	198,350.57	.00	194,383.55	.00	194,383.55

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,884 TIMES $ .200 = 976.80

********** COLUMBIA MCF CHARGE 32,514.5 TIMES $ .050 = 1,625.73

RS5500MK
CURRENT DATE: 06/01/12

COLUMBIA CHOICE PROGRAM - MAY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 05 / 2012
GAS BILLING CYCLE: 04 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 12	GTS-RES CHOICE - HEAT	03	1	13.4	44.76	.00	43.86	.00	43.86
32	05 12	TOTAL RESIDENTIAL		1	13.4	44.76	.00	43.86	.00	43.86
32	05 12	GTS-COM CHOICE - HEAT	04	59	2,005.6	7,268.14	.00	7,122.79	.00	7,122.79
32	05 12	TOTAL COMMERCIAL		59	2,005.6	7,268.14	.00	7,166.65	.00	7,166.65
32	05 12	GTS-IND CHOICE - ALL	06	1	13.8	46.09	.00	45.17	.00	45.17
32	05 12	TOTAL		61	2,032.8	7,358.99	.00	7,211.82	.00	7,211.82

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 2,032.8 TIMES $ .050 = 101.64

RS5500MK
CURRENT DATE: 06/01/12

COLUMBIA CHOICE PROGRAM - MAY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 05 / 2012
GAS BILLING CYCLE: 04 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	05 12	GTS-RES CHOICE - HEAT	03	1,581	4,569.3	22,780.25	.00	22,324.58	.00	22,324.58
32	05 12	GTS-RES CHOICE - NON-HEAT	05	27	17.3	86.33	.00	84.60	.00	84.60
32	05 12	TOTAL RESIDENTIAL		1,608	4,586.6	22,866.58	.00	22,409.18	.00	22,409.18
32	05 12	GTS-COM CHOICE - HEAT	04	1,078	15,816.7	78,869.16	.00	77,291.43	.00	77,291.43
32	05 12	GTS-COM CHOICE - NON-HEAT	06	20	446.3	2,227.06	.00	2,182.52	.00	2,182.52
32	05 12	TOTAL COMMERCIAL		1,098	16,263.0	81,096.22	.00	101,883.13	.00	101,883.13
32	05 12	GTS-IND CHOICE - ALL	06	3	34.6	181.35	.00	177.72	.00	177.72
32	05 12	TOTAL		2,709	20,884.2	104,144.15	.00	102,060.85	.00	102,060.85

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,709 TIMES $ .200 = 541.80

********** COLUMBIA MCF CHARGE 20,884.2 TIMES $ .050 = 1,044.21

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RESPONDENT: JUDY M COOPER

RS550OMK
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COLUMBIA CHOICE PROGRAM - JUNE 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 06 / 2012
GAS BILLING CYCLE: 05 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 12	GTS-RES CHOICE - HEAT	03	4,127	5,598.3	35,025.85	.00	34,325.34	.00	34,325.34
32	06 12	GTS-RES CHOICE - NON-HEAT	05	42	28.7	176.06	.00	172.51	.00	172.51
32	06 12	TOTAL RESIDENTIAL		4,169	5,627.0	35,201.91	.00	34,497.85	.00	34,497.85
32	06 12	GTS-COM CHOICE - HEAT	04	903	17,246.5	94,917.81	.00	93,019.73	.00	93,019.73
32	06 12	GTS-COM CHOICE - NON-HEAT	08	23	207.9	1,150.92	.00	1,127.92	.00	1,127.92
32	06 12	TOTAL COMMERCIAL		926	17,454.4	96,068.73	.00	128,645.50	.00	128,645.50
32	06 12	GTS-IND CHOICE - ALL	06	2	158.7	928.40	.00	909.84	.00	909.84
32	06 12	TOTAL		5,097	23,240.1	132,199.04	.00	129,555.34	.00	129,555.34

********** # OF CUSTOMERS BILLED BY COLUMBIA 5,097 TIMES $ .200 = 1,019.40

********** COLUMBIA MCF CHARGE 23,240.1 TIMES $ .050 = 1,162.01

RS550HK
CURRENT DATE: 06/30/12

COLUMBIA CHOICE PROGRAM - JUNE 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 06 / 2012
GAS BILLING CYCLE: 05 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 12	GTS-RES CHOICE - HEAT	03	132	175.5	1,341.48	.00	1,314.65	.00	1,314.65
32	06 12	GTS-RES CHOICE - NON-HEAT	05	1	2.9	19.83	.00	19.49	.06-	19.49
32	06 12	TOTAL RESIDENTIAL		133	178.4	1,361.31	.00	1,334.14	.06-	1,334.14
32	06 12	GTS-COM CHOICE - HEAT	04	1	1.1	8.79	.00	8.61	.00	8.61
32	06 12	TOTAL COMMERCIAL		1	1.1	8.79	.00	1,342.75	.06-	1,342.75
32	06 12	TOTAL		134	179.5	1,370.10	.00	1,342.75	.06-	1,342.75

********** # OF CUSTOMERS BILLED BY COLUMBIA 134 TIMES $ .200 = 26.80

********** COLUMBIA MCF CHARGE 179.5 TIMES $ .050 = 8.98

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RESPONDENT: JUDY M COOPER

RS5500HK
CURRENT DATE: 06/30/12

COLUMBIA CHOICE PROGRAM - JUNE 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

DIS BILLING CYCLE: 06 / 2012
GAS BILLING CYCLE: 05 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 12	GTS-RES CHOICE - HEAT	03	20,857	26,208.4	191,988.54	.00	188,148.93	.00	188,148.93
32	06 12	GTS-RES CHOICE - NON-HEAT	05	248	258.6	1,966.14	.00	1,926.81	.00	1,926.81
32	06 12	TOTAL RESIDENTIAL		21,105	26,467.0	193,954.68	.00	190,075.74	.00	190,075.74
32	06 12	GTS-COM CHOICE - HEAT	04	1,956	31,177.1	212,346.10	.00	208,099.30	.00	208,099.30
32	06 12	GTS-COM CHOICE - NON-HEAT	08	132	552.8	3,566.21	.00	3,494.91	.00	3,494.91
32	06 12	GTS-COM CHOICE - HEAT&A/C	13	2	7.0	48.94	.00	47.96	.00	47.96
32	06 12	TOTAL COMMERCIAL		2,090	31,736.9	215,961.25	.00	401,717.91	.00	401,717.91
32	06 12	GTS-IND CHOICE - ALL	06	5	1,949.9	12,906.53	.00	12,648.40	.00	12,648.40
32	06 12	TOTAL		23,200	60,153.8	422,822.46	.00	414,366.31	.00	414,366.31

********** # OF CUSTOMERS BILLED BY COLUMBIA 23,200 TIMES $ .200 = 4,640.00

********** COLUMBIA MCF CHARGE 60,153.8 TIMES $ .050 = 3,007.69

RS5500MK
CURRENT DATE: 06/30/12

COLUMBIA CHOICE PROGRAM - JUNE 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 06 / 2012
GAS BILLING CYCLE: 05 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 12	GTS-RES CHOICE - HEAT	03	31	50.3	261.02	.00	255.80	.00	255.80
32	06 12	GTS-RES CHOICE - NON-HEAT	05	2	1.2	6.07	.00	5.95	.00	5.95
32	06 12	TOTAL RESIDENTIAL		33	51.5	267.09	.00	261.75	.00	261.75
32	06 12	GTS-COM CHOICE - HEAT	04	74	1,437.4	7,592.52	.00	7,440.67	.00	7,440.67
32	06 12	GTS-COM CHOICE - NON-HEAT	08	1	52.8	307.30	.00	301.15	.00	301.15
32	06 12	TOTAL COMMERCIAL		75	1,490.2	7,899.82	.00	8,003.57	.00	8,003.57
32	06 12	TOTAL		108	1,541.7	8,166.91	.00	8,003.57	.00	8,003.57

********** # OF CUSTOMERS BILLED BY COLUMBIA 108 TIMES $ .200 = 21.60

********** COLUMBIA MCF CHARGE 1,541.7 TIMES $ .050 = 77.09

RS550OHK
CURRENT DATE: 06/30/12

COLUMBIA CHOICE PROGRAM - JUNE 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 06 / 2012
GAS BILLING CYCLE: 05 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 12	GTS-RES CHOICE - HEAT	05		270.7-	1,939.89-	.00	1,901.64-	.56	1,901.64-
32	06 12	TOTAL RESIDENTIAL			270.7-	1,939.89-	.00	1,901.64-	.56	1,901.64-
32	06 12	GTS-COM CHOICE - HEAT	04	4	7.2-	108.27-	.00	2,204.96-	2,141.70	2,204.96-
32	06 12	TOTAL COMMERCIAL		4	7.2-	108.27-	.00	4,106.60-	2,142.26	4,106.60-
32	06 12	GTS-IND CHOICE - ALL	06	1	.0	.00	.00	.00	.00	.00
32	06 12	TOTAL		5	277.9-	2,048.16-	.00	4,106.60-	2,142.26	4,106.60-

********** # OF CUSTOMERS BILLED BY COLUMBIA 5 TIMES $ .200 = 1.00

********** COLUMBIA MCF CHARGE 277.9- TIMES $ .050 = 13.90-

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RESPONDENT: JUDY M COOPER

RS5580HK
CURRENT DATE: 06/30/12

COLUMBIA CHOICE PROGRAM - JUNE 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 06 / 2012
GAS BILLING CYCLE: 05 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 12	GTS-RES CHOICE - HEAT	03	1	11.8	51.94	.00	50.90	.00	50.90
32	06 12	TOTAL RESIDENTIAL		1	11.8	51.94	.00	50.90	.00	50.90
32	06 12	GTS-COM CHOICE - HEAT	04	58	1,013.1	4,471.46	.00	4,382.04	.00	4,382.04
32	06 12	TOTAL COMMERCIAL		58	1,013.1	4,471.46	.00	4,432.94	.00	4,432.94
32	06 12	GTS-IND CHOICE - ALL	06	1	6.1	26.85	.00	26.31	.00	26.31
32	06 12	TOTAL		60	1,031.0	4,550.25	.00	4,459.25	.00	4,459.25

********** # OF CUSTOMERS BILLED BY COLUMBIA 60 TIMES $ .200 = 12.00

********** COLUMBIA MCF CHARGE 1,031.0 TIMES $ .050 = 51.55

RS5500MK
CURRENT DATE: 06/30/12

COLUMBIA CHOICE PROGRAM - JUNE 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 06 / 2012
GAS BILLING CYCLE: 05 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	06 12	GTS-RES CHOICE - HEAT	03	1,572	2,008.5	11,106.39	.00	10,884.17	.00	10,884.17
32	06 12	GTS-RES CHOICE - NON-HEAT	05	27	18.4	101.25	.00	99.22	.00	99.22
32	06 12	TOTAL RESIDENTIAL		1,599	2,026.9	11,207.64	.00	10,983.39	.00	10,983.39
32	06 12	GTS-COM CHOICE - HEAT	04	1,055	11,700.5	63,821.88	.00	62,545.41	.00	62,545.41
32	06 12	GTS-COM CHOICE - NON-HEAT	08	20	440.7	2,401.85	.00	2,353.81	.00	2,353.81
32	06 12	TOTAL COMMERCIAL		1,075	12,141.2	66,223.73	.00	75,882.61	.00	75,882.61
32	06 12	GTS-IND CHOICE - ALL	06	3	39.0	194.61	.00	190.72	.00	190.72
32	06 12	TOTAL		2,677	14,207.1	77,625.98	.00	76,073.33	.00	76,073.33

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,677 TIMES $ .200 = 535.40

********** COLUMBIA MCF CHARGE 14,207.1 TIMES $ .050 = 710.36

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ATTACHMENT A PAGE 85 OF 145
RESPONDENT: JUDY M COOPER

RS550OHK
CURRENT DATE: 08/01/12

COLUMBIA CHOICE PROGRAM - JULY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 07 / 2012
GAS BILLING CYCLE: 06 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 12	GTS-RES CHOICE - HEAT	03	4,084	4,496.0	27,958.08	.00	27,398.87	.00	27,398.87
32	07 12	GTS-RES CHOICE - NON-HEAT	05	41	25.3	153.51	.00	150.45	.00	150.45
32	07 12	TOTAL RESIDENTIAL		4,125	4,521.3	28,111.59	.00	27,549.32	.00	27,549.32
32	07 12	GTS-COM CHOICE - HEAT	04	905	10,435.1	58,584.50	.00	57,412.97	.00	57,412.97
32	07 12	GTS-COM CHOICE - NON-HEAT	08	24	308.7	1,679.94	.00	1,646.36	.00	1,646.36
32	07 12	TOTAL COMMERCIAL		929	10,743.8	60,264.44	.00	86,608.65	.00	86,608.65
32	07 12	GTS-IND CHOICE - ALL	06	3	89.3	534.91	.00	524.21	.00	524.21
32	07 12	TOTAL		5,057	15,354.4	88,910.94	.00	87,132.86	.00	87,132.86

********** # OF CUSTOMERS BILLED BY COLUMBIA 5,057 TIMES $ .200 = 1,011.40

********** COLUMBIA MCF CHARGE 15,354.4 TIMES $ .050 = 767.72

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 08/01/12

COLUMBIA CHOICE PROGRAM - JULY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 07 / 2012
GAS BILLING CYCLE: 06 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 12	GTS-RES CHOICE - HEAT	03	128	148.6	1,134.14	.00	1,111.46	.00	1,111.46
32	07 12	GTS-RES CHOICE - NON-HEAT	05	1	2.8	19.21	.00	18.83	.00	18.83
32	07 12	TOTAL RESIDENTIAL		129	151.4	1,153.35	.00	1,130.29	.00	1,130.29
32	07 12	GTS-COM CHOICE - HEAT	04	1	1.2	11.15	.00	10.93	.00	10.93
32	07 12	TOTAL COMMERCIAL		1	1.2	11.15	.00	1,141.22	.00	1,141.22
32	07 12	TOTAL		130	152.6	1,164.50	.00	1,141.22	.00	1,141.22

********** # OF CUSTOMERS BILLED BY COLUMBIA 130 TIMES $ .200 = 26.00

********** COLUMBIA MCF CHARGE 152.6 TIMES $ .050 = 7.63

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RS5500HK
CURRENT DATE: 08/01/12

COLUMBIA CHOICE PROGRAM - JULY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

JCS

DIS BILLING CYCLE: 07 / 2012
GAS BILLING CYCLE: 06 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 12	GTS-RES CHOICE - HEAT	05	20,621	21,717.0	151,900.39	.00	148,862.50	.00	148,862.50
32	07 12	GTS-RES CHOICE - NON-HEAT	05	243	191.8	1,365.29	.00	1,337.98	.00	1,337.98
32	07 12	TOTAL RESIDENTIAL		20,864	21,908.8	153,265.68	.00	150,200.48	.00	150,200.48
32	07 12	GTS-COM CHOICE - HEAT	04	1,943	23,123.4	146,430.74	.00	143,502.19	.00	143,502.19
32	07 12	GTS-COM CHOICE - NON-HEAT	08	134	536.8	3,364.27	.00	3,297.08	.00	3,297.08
32	07 12	GTS-COM CHOICE - HEAT&A/C	13	2	7.6	53.12	.00	52.06	.00	52.06
32	07 12	TOTAL COMMERCIAL		2,079	23,667.8	149,848.13	.00	297,051.81	.00	297,051.81
32	07 12	GTS-IND CHOICE - ALL	06	5	2,249.4	14,824.86	.00	14,528.37	.00	14,528.37
32	07 12	TOTAL		22,948	47,826.0	317,938.67	.00	311,580.18	.00	311,580.18

********** # OF CUSTOMERS BILLED BY COLUMBIA 22,948 TIMES $ .200 = 4,589.60

********** COLUMBIA MCF CHARGE 47,826.0 TIMES $ .050 = 2,391.30

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RESPONDENT: JUDY M COOPER

RS550MK
CURRENT DATE: 08/01/12

COLUMBIA CHOICE PROGRAM - JULY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 07 / 2012
GAS BILLING CYCLE: 06 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 12	GTS-RES CHOICE - HEAT	03	36	39.6	186.36	.00	182.63	.00	182.63
32	07 12	GTS-RES CHOICE - NON-HEAT	05	3	1.3	6.29	.00	6.16	.00	6.16
32	07 12	TOTAL RESIDENTIAL		39	40.9	192.65	.00	188.79	.00	188.79
32	07 12	GTS-COM CHOICE - HEAT	04	77	1,337.5	6,497.67	.00	6,367.69	.00	6,367.69
32	07 12	GTS-COM CHOICE - NON-HEAT	08	1	56.4	225.60	.00	221.09	.00	221.09
32	07 12	TOTAL COMMERCIAL		78	1,393.9	6,723.27	.00	6,777.57	.00	6,777.57
32	07 12	TOTAL		117	1,434.8	6,915.92	.00	6,777.57	.00	6,777.57

********** # OF CUSTOMERS BILLED BY COLUMBIA 117 TIMES $ .200 = 23.40

********** COLUMBIA MCF CHARGE 1,434.8 TIMES $ .050 = 71.74

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COLUMBIA CHOICE PROGRAM - JULY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 07 / 2012
GAS BILLING CYCLE: 06 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 12	GTS-RES CHOICE - HEAT	03		40.2-	254.50-	.00	249.41-	.00	249.41-
32	07 12	TOTAL RESIDENTIAL			40.2-	254.50-	.00	249.41-	.00	249.41-
32	07 12	GTS-COM CHOICE - HEAT	04		739.3-	3,967.60-	.00	3,888.25-	.00	3,888.25-
32	07 12	TOTAL COMMERCIAL			739.3-	3,967.60-	.00	4,137.66-	.00	4,137.66-
32	07 12	TOTAL			779.5-	4,222.10-	.00	4,137.66-	.00	4,137.66-

********** # OF CUSTOMERS BILLED BY COLUMBIA 0 TIMES $ .200 = .00

********** COLUMBIA MCF CHARGE 779.5- TIMES $ .050 = 38.98-

RS5500HK
CURRENT DATE: 08/01/12

COLUMBIA CHOICE PROGRAM - JULY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 07 / 2012
GAS BILLING CYCLE: 06 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 12	GTS-RES CHOICE - HEAT	03	1	10.2	47.10	.00	46.16	.00	46.16
32	07 12	TOTAL RESIDENTIAL		1	10.2	47.10	.00	46.16	.00	46.16
32	07 12	GTS-COM CHOICE - HEAT	04	59	773.7	3,622.15	.00	3,549.74	.00	3,549.74
32	07 12	TOTAL COMMERCIAL		59	773.7	3,622.15	.00	3,595.90	.00	3,595.90
32	07 12	GTS-IND CHOICE - ALL	06	1	1.3-	5.21-	.00	5.11-	.00	5.11-
32	07 12	TOTAL		61	782.6	3,664.04	.00	3,590.79	.00	3,590.79

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

xxxxxxxxxx COLUMBIA MCF CHARGE 782.6 TIMES $ .050 = 39.13

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RESPONDENT: JUDY M COOPER

KS550OMK
CURRENT DATE: 08/01/12

COLUMBIA CHOICE PROGRAM - JULY 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 07 / 2012
GAS BILLING CYCLE: 06 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	07 12	GTS-RES CHOICE - HEAT	03	1,543	1,417.6	7,258.97	.00	7,113.84	.00	7,113.84
32	07 12	GTS-RES CHOICE - NON-HEAT	05	27	14.3	74.05	.00	72.58	.00	72.58
32	07 12	TOTAL RESIDENTIAL		1,570	1,431.9	7,333.02	.00	7,186.42	.00	7,186.42
32	07 12	GTS-COM CHOICE - HEAT	04	1,045	10,638.3	55,068.27	.00	53,967.44	.00	53,967.44
32	07 12	GTS-COM CHOICE - NON-HEAT	08	20	411.4	2,130.64	.00	2,088.06	.00	2,088.06
32	07 12	TOTAL COMMERCIAL		1,065	11,049.7	57,198.91	.00	63,241.92	.00	63,241.92
32	07 12	GTS-IND CHOICE - ALL	06	3	26.0	141.70	.00	138.87	.00	138.87
32	07 12	TOTAL		2,638	12,507.6	64,673.63	.00	63,380.79	.00	63,380.79

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,638 TIMES $ .200 = 527.60

********** COLUMBIA MCF CHARGE 12,507.6 TIMES $ .050 = 625.38

RS5500HK
CURRENT DATE: 09/01/12

COLUMBIA CHOICE PROGRAM - AUGUST 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 08 / 2012
GAS BILLING CYCLE: 07 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 12	GTS-RES CHOICE - HEAT	03	4,052	4,089.2	25,944.57	.00	25,425.64	.00	25,425.64
32	08 12	GTS-RES CHOICE - NON-HEAT	05	41	24.2	150.01	.00	147.01	.00	147.01
32	08 12	TOTAL RESIDENTIAL		4,093	4,113.4	26,094.58	.00	25,572.65	.00	25,572.65
32	08 12	GTS-COM CHOICE - HEAT	04	909	11,652.4	65,561.64	.00	64,250.44	.00	64,250.44
32	08 12	GTS-COM CHOICE - NON-HEAT	08	24	284.1	1,572.51	.00	1,541.07	.00	1,541.07
32	08 12	TOTAL COMMERCIAL		933	11,936.5	67,134.15	.00	91,364.16	.00	91,364.16
32	08 12	GTS-IND CHOICE - ALL	06	4	103.6	608.56	.00	596.39	.00	596.39
32	08 12	TOTAL		5,030	16,153.5	93,837.29	.00	91,960.55	.00	91,960.55

********** # OF CUSTOMERS BILLED BY COLUMBIA 5,030 TIMES $ .200 = 1,006.00

********** COLUMBIA MCF CHARGE 16,153.5 TIMES $ .050 = 807.68

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COLUMBIA CHOICE PROGRAM - AUGUST 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 08 / 2012
GAS BILLING CYCLE: 07 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 12	GTS-RES CHOICE - HEAT	03	126	130.3	995.06	.00	975.17	.00	975.17
32	08 12	GTS-RES CHOICE - NON-HEAT	05	1	3.2	21.95	.00	21.51	.00	21.51
32	08 12	TOTAL RESIDENTIAL		127	133.5	1,017.01	.00	996.68	.00	996.68
32	08 12	GTS-COM CHOICE - HEAT	04	1	1.1	10.22	.00	10.02	.00	10.02
32	08 12	TOTAL COMMERCIAL		1	1.1	10.22	.00	1,006.70	.00	1,006.70
32	08 12	TOTAL		128	134.6	1,027.23	.00	1,006.70	.00	1,006.70

********** # OF CUSTOMERS BILLED BY COLUMBIA 128 TIMES $ .200 = 25.60

********** COLUMBIA MCF CHARGE 134.6 TIMES $ .050 = 6.73

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COLUMBIA CHOICE PROGRAM - AUGUST 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

169

DIS BILLING CYCLE: 08 / 2012
GAS BILLING CYCLE: 07 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 12	GTS-RES CHOICE - HEAT	03	20,514	20,432.1	142,959.00	.00	140,099.91	.00	140,099.91
32	08 12	GTS-RES CHOICE - NON-HEAT	05	239	180.5	1,287.97	.00	1,262.24	.00	1,262.24
32	08 12	TOTAL RESIDENTIAL		20,753	20,612.6	144,246.97	.00	141,362.15	.00	141,362.15
32	08 12	GTS-COM CHOICE - HEAT	04	1,935	20,977.7	142,715.77	.00	139,861.51	.00	139,861.51
32	08 12	GTS-COM CHOICE - NON-HEAT	08	134	558.1	3,515.11	.00	3,444.84	.00	3,444.84
32	08 12	GTS-COM CHOICE - HEAT&A/C	13	2	6.5	45.44	.00	44.53	.00	44.53
32	08 12	TOTAL COMMERCIAL		2,071	21,542.3	146,276.32	.00	284,713.03	.00	284,713.03
32	08 12	GTS-IND CHOICE - ALL	06	5	2,010.0	13,234.42	.00	12,969.73	.00	12,969.73
32	08 12	TOTAL		22,829	44,164.9	303,757.71	.00	297,682.76	.00	297,682.76

********** # OF CUSTOMERS BILLED BY COLUMBIA 22,829 TIMES $ .200 = 4,565.80

********** COLUMBIA MCF CHARGE 44,164.9 TIMES $ .050 = 2,208.25

RSS500MK
CURRENT DATE: 09/01/12

COLUMBIA CHOICE PROGRAM - AUGUST 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 08 / 2012
GAS BILLING CYCLE: 07 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 12	GTS-RES CHOICE - HEAT	05	38	43.1	206.18	.00	202.06	.00	202.06
32	08 12	GTS-RES CHOICE - NON-HEAT	05	3	1.1	5.49	.00	5.38	.00	5.38
32	08 12	TOTAL RESIDENTIAL		41	44.2	211.67	.00	207.44	.00	207.44
32	08 12	GTS-COM CHOICE - HEAT	04	77	1,310.2	5,790.54	.00	5,674.69	.00	5,674.69
32	08 12	GTS-COM CHOICE - NON-HEAT	08	1	52.8	211.20	.00	206.98	.00	206.98
32	08 12	TOTAL COMMERCIAL		78	1,363.0	6,001.74	.00	6,089.11	.00	6,089.11
32	08 12	TOTAL		119	1,407.2	6,213.41	.00	6,089.11	.00	6,089.11

********** # OF CUSTOMERS BILLED BY COLUMBIA 119 TIMES $ .200 = 23.80

********** COLUMBIA MCF CHARGE 1,407.2 TIMES $ .050 = 70.36

RS5500HK
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COLUMBIA CHOICE PROGRAM - AUGUST 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DTS BILLING CYCLE: 08 / 2012
GAS BILLING CYCLE: 07 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 12	GTS-RES CHOICE - HEAT	03		14.2	157.55	.00	134.80	.00	134.80
32	08 12	TOTAL RESIDENTIAL			14.2	157.55	.00	134.80	.00	134.80
32	08 12	GTS-COM CHOICE - HEAT	04		14.7-	104.37-	.00	102.28-	.00	102.28-
32	08 12	TOTAL COMMERCIAL			14.7-	104.37-	.00	32.52	.00	32.52
32	08 12	TOTAL			.5-	33.18	.00	32.52	.00	32.52

********** # OF CUSTOMERS BILLED BY COLUMBIA 0 TIMES $ .200 = .00

********** COLUMBIA MCF CHARGE .5- TIMES $ .050 = .03-

RS5508HK
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COLUMBIA CHOICE PROGRAM - AUGUST 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 08 / 2012
GAS BILLING CYCLE: 07 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 12	GTS-RES CHOICE - HEAT	03	1	10.8	53.52	.00	52.45	.00	52.45
32	08 12	TOTAL RESIDENTIAL		1	10.8	53.52	.00	52.45	.00	52.45
32	08 12	GTS-COM CHOICE - HEAT	04	59	696.6	3,494.93	.00	3,425.00	.00	3,425.00
32	08 12	TOTAL COMMERCIAL		59	696.6	3,494.93	.00	3,477.45	.00	3,477.45
32	08 12	GTS-IND CHOICE - ALL	06	1	2.5	12.39	.00	12.14	.00	12.14
32	08 12	TOTAL		61	709.9	3,560.84	.00	3,489.59	.00	3,489.59

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA HCF CHARGE 709.9 TIMES $ .050 = 35.50

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COLUMBIA CHOICE PROGRAM - AUGUST 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 08 / 2012
GAS BILLING CYCLE: 07 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	08 12	GTS-RES CHOICE - HEAT	03	1,526	1,992.8	9,935.77	.00	9,737.02	.00	9,737.02
32	08 12	GTS-RES CHOICE - NON-HEAT	05	27	10.1	50.42	.00	49.41	.00	49.41
32	08 12	TOTAL RESIDENTIAL		1,553	2,002.9	9,986.19	.00	9,786.43	.00	9,786.43
32	08 12	GTS-COM CHOICE - HEAT	04	1,038	10,015.2	49,939.48	.00	48,940.57	.00	48,940.57
32	08 12	GTS-COM CHOICE - NON-HEAT	08	20	406.0	2,025.95	.00	1,985.44	.00	1,985.44
32	08 12	TOTAL COMMERCIAL		1,058	10,421.2	51,965.43	.00	60,712.44	.00	60,712.44
32	08 12	GTS-IND CHOICE - ALL	06	5	21.0	108.76	.00	106.58	.00	106.58
32	08 12	TOTAL		2,614	12,445.1	62,060.38	.00	60,819.02	.00	60,819.02

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,614 TIMES $ .200 = 522.80

********** COLUMBIA MCF CHARGE 12,445.1 TIMES $ .050 = 622.26

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RESPONDENT: JUDY M COOPER

R55500MK
CURRENT DATE: 09/29/12

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 09 / 2012
GAS BILLING CYCLE: 08 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 12	GTS-RES CHOICE - HEAT	03	4,020	4,542.9	28,559.80	.00	27,988.67	.00	27,988.67
32	09 12	GTS-RES CHOICE - NON-HEAT	05	39	26.2	158.62	.00	155.44	.00	155.44
32	09 12	TOTAL RESIDENTIAL		4,059	4,569.1	28,718.42	.00	28,144.11	.00	28,144.11
32	09 12	GTS-COM CHOICE - HEAT	04	900	22,740.6	130,901.25	.00	128,283.29	.00	128,283.29
32	09 12	GTS-COM CHOICE - NON-HEAT	08	24	263.4	1,463.73	.00	1,434.45	.00	1,434.45
32	09 12	TOTAL COMMERCIAL		924	23,004.0	132,364.98	.00	157,861.85	.00	157,861.85
32	09 12	GTS-IND CHOICE - ALL	06	3	100.2	586.17	.00	574.45	.00	574.45
32	09 12	TOTAL		4,986	27,673.3	161,669.57	.00	158,436.30	.00	158,436.30

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,986 TIMES $ .200 = 997.20

********** COLUMBIA MCF CHARGE 27,673.3 TIMES $ .050 = 1,383.67

RS5500HK
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COLUMBIA CHOICE PROGRAM - SEPTEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 09 / 2012
GAS BILLING CYCLE: 08 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 12	GTS-RES CHOICE - HEAT	03	119	144.4	1,154.22	.00	1,131.14	.00	1,131.14
32	09 12	GTS-RES CHOICE - NON-HEAT	05	1	2.8	19.21	.00	18.83	.00	18.83
32	09 12	TOTAL RESIDENTIAL		120	147.2	1,173.43	.00	1,149.97	.00	1,149.97
32	09 12	GTS-COM CHOICE - HEAT	04	1	1.1	10.22	.00	10.02	.00	10.02
32	09 12	TOTAL COMMERCIAL		1	1.1	10.22	.00	1,159.99	.00	1,159.99
32	09 12	TOTAL		121	148.3	1,183.65	.00	1,159.99	.00	1,159.99

********** # OF CUSTOMERS BILLED BY COLUMBIA 121 TIMES $ .200 = 24.20

********** COLUMBIA MCF CHARGE 148.3 TIMES $ .050 = 7.42

RS550MK
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COLUMBIA CHOICE PROGRAM - SEPTEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

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DIS BILLING CYCLE: 09 / 2012
GAS BILLING CYCLE: 08 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 12	GTS-RES CHOICE - HEAT	03	20,390	20,747.8	145,130.32	.00	142,227.72	.00	142,227.72
32	09 12	GTS-RES CHOICE - NON-HEAT	05	235	222.9	1,561.18	.00	1,529.99	.00	1,529.99
32	09 12	TOTAL RESIDENTIAL		20,625	20,970.7	146,691.50	.00	143,757.71	.00	143,757.71
32	09 12	GTS-COM CHOICE - HEAT	04	1,925	24,972.9	166,506.99	.00	163,177.14	.00	163,177.14
32	09 12	GTS-COM CHOICE - NON-HEAT	08	133	670.8	4,304.60	.00	4,218.60	.00	4,218.60
32	09 12	GTS-COM CHOICE - HEAT&A/C	13	2	8.0	55.92	.00	54.81	.00	54.81
32	09 12	TOTAL COMMERCIAL		2,060	25,651.7	170,867.51	.00	311,208.26	.00	311,208.26
32	09 12	GTS-IND CHOICE - ALL	06	5	2,119.5	12,854.68	.00	12,597.59	.00	12,597.59
32	09 12	TOTAL		22,690	48,741.9	330,413.69	.00	323,805.85	.00	323,805.85

********** # OF CUSTOMERS BILLED BY COLUMBIA 22,690 TIMES $ .200 = 4,538.00

********** COLUMBIA MCF CHARGE 48,741.9 TIMES $ .050 = 2,437.10

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RS5500HK
CURRENT DATE: 09/29/12

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 09 / 2012
GAS BILLING CYCLE: 08 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 12	GTS-RES CHOICE - HEAT	03	46	56.3	273.00	.00	267.53	.00	267.53
32	09 12	GTS-RES CHOICE - NON-HEAT	05	3	1.4	6.79	.00	6.65	.00	6.65
32	09 12	TOTAL RESIDENTIAL		49	57.7	279.79	.00	274.18	.00	274.18
32	09 12	GTS-COM CHOICE - HEAT	04	79	1,537.6	6,810.90	.00	6,674.66	.00	6,674.66
32	09 12	GTS-COM CHOICE - NON-HEAT	08	1	53.7	214.80	.00	210.50	.00	210.50
32	09 12	TOTAL COMMERCIAL		80	1,591.3	7,025.70	.00	7,159.34	.00	7,159.34
32	09 12	TOTAL		129	1,649.0	7,305.49	.00	7,159.34	.00	7,159.34

********** # OF CUSTOMERS BILLED BY COLUMBIA 129 TIMES $ .200 = 25.80

********** COLUMBIA MCF CHARGE 1,649.0 TIMES $ .050 = 82.45

RS500MK
CURRENT DATE: 09/29/12

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 09 / 2012
GAS BILLING CYCLE: 08 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 12	GTS-RES CHOICE - HEAT	03		12.4-	80.53-	.00	78.93-	.00	78.93-
32	09 12	TOTAL RESIDENTIAL			12.4-	80.53-	.00	78.93-	.00	78.93-
32	09 12	GTS-COM CHOICE - HEAT	04		5.5-	38.44-	.00	37.67-	.00	37.67-
32	09 12	TOTAL COMMERCIAL			5.5-	38.44-	.00	116.60-	.00	116.60-
32	09 12	TOTAL			17.9-	118.97-	.00	116.60-	.00	116.60-

********** # OF CUSTOMERS BILLED BY COLUMBIA   0 TIMES $ .200 =   .00

********** COLUMBIA MCF CHARGE   17.9- TIMES $ .050 =   .90-

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 09/29/12

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 09 / 2012
GAS BILLING CYCLE: 08 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 12	GTS-RES CHOICE - HEAT	03	1	10.2	57.22	.00	56.08	.00	56.08
32	09 12	TOTAL RESIDENTIAL		1	10.2	57.22	.00	56.08	.00	56.08
32	09 12	GTS-COM CHOICE - HEAT	04	59	909.7	5,099.42	.00	4,997.43	.00	4,997.43
32	09 12	TOTAL COMMERCIAL		59	909.7	5,099.42	.00	5,053.51	.00	5,053.51
32	09 12	GTS-IND CHOICE - ALL	06	1	9.4	52.73	.00	51.68	.00	51.68
32	09 12	TOTAL		61	929.3	5,209.37	.00	5,105.19	.00	5,105.19

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 929.3 TIMES $ .050 = 46.47

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 09/29/12

COLUMBIA CHOICE PROGRAM - SEPTEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 09 / 2012
GAS BILLING CYCLE: 08 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	09 12	GTS-RES CHOICE - HEAT	03	1,512	1,606.3	7,951.17	.00	7,792.08	.00	7,792.08
32	09 12	GTS-RES CHOICE - NON-HEAT	05	27	10.5	52.08	.00	51.04	.00	51.04
32	09 12	TOTAL RESIDENTIAL		1,539	1,616.8	8,003.25	.00	7,843.12	.00	7,843.12
32	09 12	GTS-COM CHOICE - HEAT	04	1,024	10,665.1	52,879.61	.00	51,821.72	.00	51,821.72
32	09 12	GTS-COM CHOICE - NON-HEAT	08	20	413.4	2,050.42	.00	2,009.43	.00	2,009.43
32	09 12	TOTAL COMMERCIAL		1,044	11,078.5	54,930.03	.00	61,674.27	.00	61,674.27
32	09 12	GTS-IND CHOICE - ALL	06	5	23.0	114.77	.00	112.47	.00	112.47
32	09 12	TOTAL		2,586	12,718.3	63,048.05	.00	61,786.74	.00	61,786.74

********* # OF CUSTOMERS BILLED BY COLUMBIA 2,586 TIMES $ .200 = 517.20

********* COLUMBIA MCF CHARGE 12,718.3 TIMES $ .050 = 635.92

PSC CASE NO. 2013-00167
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 11/01/12

COLUMBIA CHOICE PROGRAM - OCTOBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

OIS BILLING CYCLE: 10 / 2012
GAS BILLING CYCLE: 09 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 12	GTS-RES CHOICE - HEAT	03	4,000	8,448.8	51,173.20	.00	50,149.80	.00	50,149.80
32	10 12	GTS-RES CHOICE - NON-HEAT	05	37	30.2	179.50	.00	175.92	.00	175.92
32	10 12	TOTAL RESIDENTIAL		4,037	8,479.0	51,352.70	.00	50,325.72	.00	50,325.72
32	10 12	GTS-COM CHOICE - HEAT	04	904	11,861.1	67,055.90	.00	65,714.95	.00	65,714.95
32	10 12	GTS-COM CHOICE - NON-HEAT	08	24	274.1	1,517.23	.00	1,486.90	.00	1,486.90
32	10 12	TOTAL COMMERCIAL		928	12,135.2	68,573.13	.00	117,527.57	.00	117,527.57
32	10 12	GTS-IND CHOICE - ALL	06	3	590.0	3,451.51	.00	3,382.48	.00	3,382.48
32	10 12	TOTAL		4,968	21,204.2	123,377.34	.00	120,910.05	.00	120,910.05

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,968 TIMES $ .200 = 993.60

********** COLUMBIA MCF CHARGE 21,204.2 TIMES $ .050 = 1,060.21

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RESPONDENT: JUDY M COOPER

RS550OMK
CURRENT DATE: 11/01/12

COLUMBIA CHOICE PROGRAM - OCTOBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 10 / 2012
GAS BILLING CYCLE: 09 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 12	GTS-RES CHOICE - HEAT	03	119	240.4	1,928.34	.00	1,889.77	.00	1,889.77
32	10 12	GTS-RES CHOICE - NON-HEAT	05	1	2.8	19.21	.00	18.83	.00	18.83
32	10 12	TOTAL RESIDENTIAL		120	243.2	1,947.55	.00	1,908.60	.00	1,908.60
32	10 12	GTS-COM CHOICE - HEAT	04	1	4.1	38.09	.00	37.33	.00	37.33
32	10 12	TOTAL COMMERCIAL		1	4.1	38.09	.00	1,945.93	.00	1,945.93
32	10 12	TOTAL		121	247.3	1,985.64	.00	1,945.93	.00	1,945.93

********** # OF CUSTOMERS BILLED BY COLUMBIA 121 TIMES $ .200 = 24.20

********** COLUMBIA MCF CHARGE 247.3 TIMES $ .050 = 12.37

RS5500MK
CURRENT DATE: 11/01/12

COLUMBIA CHOICE PROGRAM - OCTOBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

DIS BILLING CYCLE: 10 / 2012
GAS BILLING CYCLE: 09 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 12	GTS-RES CHOICE - HEAT	03	20,265	40,627.0	286,510.10	.00	280,779.98	.00	280,779.98
32	10 12	GTS-RES CHOICE - NON-HEAT	05	236	258.4	1,833.68	.00	1,797.06	.00	1,797.06
32	10 12	TOTAL RESIDENTIAL		20,501	40,885.4	288,343.78	.00	282,577.04	.00	282,577.04
32	10 12	GTS-COM CHOICE - HEAT	04	1,910	32,401.5	214,005.94	.00	209,726.23	.00	209,726.23
32	10 12	GTS-COM CHOICE - NON-HEAT	08	131	650.3	4,005.90	.00	3,925.79	.00	3,925.79
32	10 12	GTS-COM CHOICE - HEAT&A/C	13	2	8.1	56.62	.00	55.49	.00	55.49
32	10 12	TOTAL COMMERCIAL		2,043	33,059.9	218,068.46	.00	496,284.55	.00	496,284.55
32	10 12	GTS-IND CHOICE - ALL	06	5	2,134.5	12,896.06	.00	12,638.14	.00	12,638.14
32	10 12	TOTAL		22,549	76,079.8	519,308.30	.00	508,922.69	.00	508,922.69

********** # OF CUSTOMERS BILLED BY COLUMBIA 22,549 TIMES $ .200 = 4,509.80

********** COLUMBIA MCF CHARGE 76,079.8 TIMES $ .050 = 3,803.99

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RESPONDENT: JUDY M COOPER

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COLUMBIA CHOICE PROGRAM - OCTOBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 10 / 2012
GAS BILLING CYCLE: 09 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 12	GTS-RES CHOICE - HEAT	03	47	103.5	490.64	.00	480.83	.00	480.83
32	10 12	GTS-RES CHOICE - NON-HEAT	05	3	2.6	12.38	.00	12.13	.00	12.13
32	10 12	TOTAL RESIDENTIAL		50	106.1	503.02	.00	492.96	.00	492.96
32	10 12	GTS-COM CHOICE - HEAT	04	81	1,891.8	8,520.34	.00	8,349.92	.00	8,349.92
32	10 12	GTS-COM CHOICE - NON-HEAT	06	1	60.8	243.20	.00	238.34	.00	238.34
32	10 12	TOTAL COMMERCIAL		82	1,952.6	8,763.54	.00	9,081.22	.00	9,081.22
32	10 12	TOTAL		132	2,058.7	9,266.56	.00	9,081.22	.00	9,081.22

********** # OF CUSTOMERS BILLED BY COLUMBIA 132 TIMES $ .200 = 26.40

********** COLUMBIA MCF CHARGE 2,058.7 TIMES $ .050 = 102.94

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COLUMBIA CHOICE PROGRAM - OCTOBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 10 / 2012
GAS BILLING CYCLE: 09 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 12	GTS-RES CHOICE - HEAT	03		2.2-	16.64-	.00	16.30-	.00	16.30-
32	10 12	TOTAL RESIDENTIAL			2.2-	16.64-	.00	16.30-	.00	16.30-
32	10 12	GTS-COM CHOICE - HEAT	04		.8-	5.55-	.00	5.44-	.00	5.44-
32	10 12	TOTAL COMMERCIAL			.8-	5.55-	.00	21.74-	.00	21.74-
32	10 12	TOTAL			3.0-	22.19-	.00	21.74-	.00	21.74-

********** # OF CUSTOMERS BILLED BY COLUMBIA 0 TIMES $ .200 = .00

********** COLUMBIA MCF CHARGE 3.0- TIMES $ .050 = .15-

RS550MK
CURRENT DATE: 11/01/12

COLUMBIA CHOICE PROGRAM - OCTOBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 10 / 2012
GAS BILLING CYCLE: 09 / 2012

CD	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 12	GTS-RES CHOICE - HEAT	03	2	10.8	61.13	.00	59.91	.00	59.91
32	10 12	TOTAL RESIDENTIAL		2	10.8	61.13	.00	59.91	.00	59.91
32	10 12	GTS-COM CHOICE - HEAT	04	61	2,542.3	14,421.80	.00	14,133.37	.00	14,133.37
32	10 12	TOTAL COMMERCIAL		61	2,542.3	14,421.80	.00	14,193.28	.00	14,193.28
32	10 12	GTS-IND CHOICE - ALL	06	1	73.7	417.14	.00	408.80	.00	408.80
32	10 12	TOTAL		64	2,626.8	14,900.07	.00	14,602.08	.00	14,602.08

********** # OF CUSTOMERS BILLED BY COLUMBIA 64 TIMES $ .200 = 12.80

********** COLUMBIA MCF CHARGE 2,626.8 TIMES $ .050 = 131.34

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STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS550MK
CURRENT DATE: 11/01/12

COLUMBIA CHOICE PROGRAM - OCTOBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 10 / 2012
GAS BILLING CYCLE: 09 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	10 12	GTS-RES CHOICE - HEAT	03	1,496	2,669.5	12,155.01	.00	11,892.33	.00	11,892.33
32	10 12	GTS-RES CHOICE - NON-HEAT	05	27	11.5	52.82	.00	51.75	.00	51.75
32	10 12	TOTAL RESIDENTIAL		1,523	2,681.0	12,187.83	.00	11,944.08	.00	11,944.08
32	10 12	GTS-COM CHOICE - HEAT	04	1,019	12,802.1	58,785.04	.00	57,609.09	.00	57,609.09
32	10 12	GTS-COM CHOICE - NON-HEAT	08	20	459.0	2,108.19	.00	2,066.02	.00	2,066.02
32	10 12	TOTAL COMMERCIAL		1,039	13,261.1	60,893.23	.00	71,619.19	.00	71,619.19
32	10 12	GTS-IND CHOICE - ALL	06	3	8.2	40.60	.00	39.79	.00	39.79
32	10 12	TOTAL		2,565	15,950.3	73,121.66	.00	71,658.98	.00	71,658.98

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,565 TIMES $ .200 = 513.00

********** COLUMBIA MCF CHARGE 15,950.3 TIMES $ .050 = 797.52

RS5500HK
CURRENT DATE: 12/01/12

COLUMBIA CHOICE PROGRAM - NOVEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 11 / 2012
GAS BILLING CYCLE: 10 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 12	GTS-RES CHOICE - HEAT	03	3,958	24,228.3	159,089.34	.00	155,907.58	.00	155,907.58
32	11 12	GTS-RES CHOICE - NON-HEAT	05	36	54.1	332.00	.00	325.38	.00	325.38
32	11 12	TOTAL RESIDENTIAL		3,994	24,282.4	159,421.34	.00	156,232.96	.00	156,232.96
32	11 12	GTS-COM CHOICE - HEAT	04	902	41,472.3	248,100.33	.00	243,138.32	.00	243,138.32
32	11 12	GTS-COM CHOICE - NON-HEAT	08	24	294.1	1,639.97	.00	1,607.17	.00	1,607.17
32	11 12	TOTAL COMMERCIAL		926	41,766.4	249,740.30	.00	400,978.45	.00	400,978.45
32	11 12	GTS-IND CHOICE - ALL	06	3	2,339.3	13,684.91	.00	13,411.21	.00	13,411.21
32	11 12	TOTAL		4,923	68,388.1	422,846.55	.00	414,389.66	.00	414,389.66

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,923 TIMES $ .200 = 984.60

********** COLUMBIA MCF CHARGE 68,388.1 TIMES $ .050 = 3,419.41

RS5500MK
CURRENT DATE: 12/01/12

COLUMBIA CHOICE PROGRAM - NOVEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 11 / 2012
GAS BILLING CYCLE: 10 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 12	GTS-RES CHOICE - HEAT	03	118	706.5	5,879.79	.00	5,762.18	.00	5,762.18
32	11 12	GTS-RES CHOICE - NON-HEAT	05	1	2.9	19.89	.00	19.49	.00	19.49
32	11 12	TOTAL RESIDENTIAL		119	709.4	5,899.68	.00	5,781.67	.00	5,781.67
32	11 12	GTS-COM CHOICE - HEAT	04	1	11.8	113.16	.00	110.90	.00	110.90
32	11 12	TOTAL COMMERCIAL		1	11.8	113.16	.00	5,892.57	.00	5,892.57
32	11 12	TOTAL		120	721.2	6,012.84	.00	5,892.57	.00	5,892.57

********** # OF CUSTOMERS BILLED BY COLUMBIA 120 TIMES $ .200 = 24.00

********** COLUMBIA MCF CHARGE 721.2 TIMES $ .050 = 36.06

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RESPONDENT: JUDY M COOPER

RS5500HK
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COLUMBIA CHOICE PROGRAM - NOVEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

165

DIS BILLING CYCLE: 11 / 2012
GAS BILLING CYCLE: 10 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 12	GTS-RES CHOICE - HEAT	03	20,128	122,811.3	868,394.05	.00	851,026.36	.06-	851,026.36
32	11 12	GTS-RES CHOICE - NON-HEAT	05	236	451.3	3,363.89	.00	3,296.59	.00	3,296.59
32	11 12	TOTAL RESIDENTIAL		20,364	123,262.6	871,757.94	.00	854,322.95	.06-	854,322.95
32	11 12	GTS-COM CHOICE - HEAT	04	1,902	65,242.1	437,607.91	.00	428,856.05	.00	428,856.05
32	11 12	GTS-COM CHOICE - NON-HEAT	08	131	751.9	4,659.12	.00	4,565.99	.00	4,565.99
32	11 12	GTS-COM CHOICE - HEAT&A/C	13	2	49.4	345.31	.00	338.41	.00	338.41
32	11 12	TOTAL COMMERCIAL		2,035	66,043.4	442,612.34	.00	1,288,083.40	.06-	1,288,083.40
32	11 12	GTS-IND CHOICE - ALL	06	5	2,304.8	13,990.34	.00	13,710.54	.00	13,710.54
32	11 12	TOTAL		22,404	191,610.8	1,328,360.62	.00	1,301,793.94	.06-	1,301,793.94

********** # OF CUSTOMERS BILLED BY COLUMBIA 22,404 TIMES $ .200 = 4,480.80

********** COLUMBIA MCF CHARGE 191,610.8 TIMES $ .050 = 9,580.54

RS5500MK
CURRENT DATE: 12/01/12

COLUMBIA CHOICE PROGRAM - NOVEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 11 / 2012
GAS BILLING CYCLE: 10 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 12	GTS-RES CHOICE - HEAT	03	48	379.9	1,845.35	.00	1,808.44	.00	1,808.44
32	11 12	GTS-RES CHOICE - NON-HEAT	05	3	10.2	49.11	.00	48.13	.00	48.13
32	11 12	TOTAL RESIDENTIAL		51	390.1	1,894.46	.00	1,856.57	.00	1,856.57
32	11 12	GTS-COM CHOICE - HEAT	04	81	4,021.6	18,338.74	.00	17,971.97	.00	17,971.97
32	11 12	GTS-COM CHOICE - NON-HEAT	08	1	58.0	232.00	.00	227.36	.00	227.36
32	11 12	TOTAL COMMERCIAL		82	4,079.6	18,570.74	.00	20,055.90	.00	20,055.90
32	11 12	TOTAL		133	4,469.7	20,465.20	.00	20,055.90	.00	20,055.90

********** # OF CUSTOMERS BILLED BY COLUMBIA 133 TIMES $ .200 = 26.60

********** COLUMBIA MCF CHARGE 4,469.7 TIMES $ .050 = 223.49

RS5500HK
CURRENT DATE: 12/01/12

COLUMBIA CHOICE PROGRAM - NOVEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 11 / 2012
GAS BILLING CYCLE: 10 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 12	GTS-RES CHOICE - HEAT	03		1.1	7.99	.00	7.83	.00	7.83
32	11 12	TOTAL RESIDENTIAL			1.1	7.99	.00	7.83	.00	7.83
32	11 12	TOTAL COMMERCIAL			.0	.00	.00	7.83	.00	7.83
32	11 12	TOTAL			1.1	7.99	.00	7.83	.00	7.83

********** # OF CUSTOMERS BILLED BY COLUMBIA 0 TIMES $ .200 = .00

********** COLUMBIA MCF CHARGE 1.1 TIMES $ .050 = .06

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 12/01/12

COLUMBIA CHOICE PROGRAM - NOVEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 11 / 2012
GAS BILLING CYCLE: 10 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 12	GTS-RES CHOICE - HEAT	03	2	10.4	68.07	.00	66.71	.00	66.71
32	11 12	TOTAL RESIDENTIAL		2	10.4	68.07	.00	66.71	.00	66.71
32	11 12	GTS-COM CHOICE - HEAT	04	61	6,575.8	42,294.67	.00	41,448.81	.00	41,448.81
32	11 12	TOTAL COMMERCIAL		61	6,575.8	42,294.67	.00	41,515.52	.00	41,515.52
32	11 12	GTS-IND CHOICE - ALL	06	1	126.5	827.94	.00	811.38	.00	811.38
32	11 12	TOTAL		64	6,712.7	43,190.68	.00	42,326.90	.00	42,326.90

********** # OF CUSTOMERS BILLED BY COLUMBIA 64 TIMES $ .200 = 12.80

********** COLUMBIA MCF CHARGE 6,712.7 TIMES $ .050 = 335.64

RS5500NK
CURRENT DATE: 12/01/12

COLUMBIA CHOICE PROGRAM - NOVEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 11 / 2012
GAS BILLING CYCLE: 10 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	11 12	GTS-RES CHOICE - HEAT	03	1,754	9,705.7	58,138.37	.00	56,975.59	.00	56,975.59
32	11 12	GTS-RES CHOICE - NON-HEAT	05	29	24.9	149.15	.00	146.17	.00	146.17
32	11 12	TOTAL RESIDENTIAL		1,783	9,730.6	58,287.52	.00	57,121.76	.00	57,121.76
32	11 12	GTS-COM CHOICE - HEAT	04	1,016	25,514.0	152,838.21	.00	149,781.34	.00	149,781.34
32	11 12	GTS-COM CHOICE - NON-HEAT	08	20	482.4	2,889.57	.00	2,831.79	.00	2,831.79
32	11 12	TOTAL COMMERCIAL		1,036	25,996.4	155,727.78	.00	209,734.89	.00	209,734.89
32	11 12	GTS-IND CHOICE - ALL	06	3	29.0	137.39	.00	134.64	.00	134.64
32	11 12	TOTAL		2,822	35,756.0	214,152.69	.00	209,869.53	.00	209,869.53

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,822 TIMES $ .200 = 564.40

********** COLUMBIA MCF CHARGE 35,756.0 TIMES $ .050 = 1,787.80

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 120 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 01/01/13

COLUMBIA CHOICE PROGRAM - DECEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 12 / 2012
GAS BILLING CYCLE: 11 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 12	GTS-RES CHOICE - HEAT	03	3,930	38,915.6	254,422.65	.00	249,334.37	.16-	249,334.37
32	12 12	GTS-RES CHOICE - NON-HEAT	05	36	73.0	462.18	.00	452.93	.00	452.93
32	12 12	TOTAL RESIDENTIAL		3,966	38,988.6	254,884.83	.00	249,787.30	.16-	249,787.30
32	12 12	GTS-COM CHOICE - HEAT	04	893	65,628.7	390,453.87	.00	382,644.89	.00	382,644.89
32	12 12	GTS-COM CHOICE - NON-HEAT	08	25	320.1	1,770.60	.00	1,735.20	.00	1,735.20
32	12 12	TOTAL COMMERCIAL		918	65,948.8	392,224.47	.00	634,167.39	.16-	634,167.39
32	12 12	GTS-IND CHOICE - ALL	06	3	3,061.3	17,908.61	.00	17,550.44	.00	17,550.44
32	12 12	TOTAL		4,887	107,998.7	665,017.91	.00	651,717.83	.16-	651,717.83

**********> # OF CUSTOMERS BILLED BY COLUMBIA 4,887 TIMES $ .200 = 977.40

********** COLUMBIA MCF CHARGE 107,998.7 TIMES $ .050 = 5,399.94

RS5500MK
CURRENT DATE: 01/01/13

COLUMBIA CHOICE PROGRAM - DECEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 12 / 2012
GAS BILLING CYCLE: 11 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 12	GTS-RES CHOICE - HEAT	03	118	1,054.6	8,800.09	.00	8,624.08	.00	8,624.08
32	12 12	GTS-RES CHOICE - NON-HEAT	05	1	3.8	26.07	.00	25.55	.00	25.55
32	12 12	TOTAL RESIDENTIAL		119	1,058.4	8,826.16	.00	8,649.63	.00	8,649.63
32	12 12	GTS-COM CHOICE - HEAT	04	1	12.4	118.92	.00	116.54	.00	116.54
32	12 12	TOTAL COMMERCIAL		1	12.4	118.92	.00	8,766.17	.00	8,766.17
32	12 12	TOTAL		120	1,070.8	8,945.08	.00	8,766.17	.00	8,766.17

********** # OF CUSTOMERS BILLED BY COLUMBIA 120 TIMES $ .200 = 24.00

********** COLUMBIA MCF CHARGE 1,070.8 TIMES $ .050 = 53.54

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STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 01/01/13

COLUMBIA CHOICE PROGRAM - DECEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

IGS

DIS BILLING CYCLE: 12 / 2012
GAS BILLING CYCLE: 11 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 12	GTS-RES CHOICE - HEAT	03	19,999	201,907.3	1,427,591.56	.00	1,399,039.70	.00	1,399,039.70
32	12 12	GTS-RES CHOICE - NON-HEAT	05	234	739.7	5,431.30	.00	5,322.73	.00	5,322.73
32	12 12	TOTAL RESIDENTIAL		20,233	202,647.0	1,433,022.86	.00	1,404,362.43	.00	1,404,362.43
32	12 12	GTS-COM CHOICE - HEAT	04	1,896	98,365.3	669,025.49	.00	655,645.14	.00	655,645.14
32	12 12	GTS-COM CHOICE - NON-HEAT	08	130	948.6	5,979.44	.00	5,859.92	.00	5,859.92
32	12 12	GTS-COM CHOICE - HEAT&A/C	13	2	91.9	642.38	.00	629.53	.00	629.53
32	12 12	TOTAL COMMERCIAL		2,028	99,405.8	675,647.31	.00	2,066,497.02	.00	2,066,497.02
32	12 12	GTS-IND CHOICE - ALL	06	5	2,522.3	15,402.83	.00	15,094.78	.00	15,094.78
32	12 12	TOTAL		22,266	304,575.1	2,124,073.00	.00	2,081,591.80	.00	2,081,591.80

********** # OF CUSTOMERS BILLED BY COLUMBIA 22,266 TIMES $ .200 = 4,453.20

********** COLUMBIA MCF CHARGE 304,575.1 TIMES $ .050 = 15,228.76

PSC CASE NO. 2013-00167
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 01/01/13

COLUMBIA CHOICE PROGRAM - DECEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 12 / 2012
GAS BILLING CYCLE: 11 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 12	GTS-RES CHOICE - HEAT	03	48	570.1	2,819.99	.00	2,763.58	.00	2,763.58
32	12 12	GTS-RES CHOICE - NON-HEAT	05	3	11.2	53.62	.00	52.55	.00	52.55
32	12 12	TOTAL RESIDENTIAL		51	581.3	2,873.61	.00	2,816.13	.00	2,816.13
32	12 12	GTS-COM CHOICE - HEAT	04	81	6,941.7	31,022.07	.00	30,401.57	.00	30,401.57
32	12 12	GTS-COM CHOICE - NON-HEAT	08	1	55.5	222.00	.00	217.56	.00	217.56
32	12 12	TOTAL COMMERCIAL		82	6,997.2	31,244.07	.00	33,435.26	.00	33,435.26
32	12 12	TOTAL		133	7,578.5	34,117.68	.00	33,435.26	.00	33,435.26

********** # OF CUSTOMERS BILLED BY COLUMBIA 133 TIMES $ .200 = 26.60

********** COLUMBIA MCF CHARGE 7,578.5 TIMES $ .050 = 378.93

RS5500MK
CURRENT DATE: 01/01/13

COLUMBIA CHOICE PROGRAM - DECEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 12 / 2012
GAS BILLING CYCLE: 11 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 12	GTS-RES CHOICE - HEAT	03		9.3-	69.66-	.00	68.27-	.00	68.27-
32	12 12	TOTAL RESIDENTIAL			9.3-	69.66-	.00	68.27-	.00	68.27-
32	12 12	GTS-COM CHOICE - HEAT	04		.0	.00	.00	.00	.00	.00
32	12 12	TOTAL COMMERCIAL			.0	.00	.00	68.27-	.00	68.27-
32	12 12	TOTAL			9.3-	69.66-	.00	68.27-	.00	68.27-

xxxxxxxxxx # OF CUSTOMERS BILLED BY COLUMBIA 0 TIMES $ .200 = .00

xxxxxxxxxx COLUMBIA MCF CHARGE 9.3- TIMES $ .050 = .47-

RS5500MK
CURRENT DATE: 01/01/13

COLUMBIA CHOICE PROGRAM - DECEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 12 / 2012
GAS BILLING CYCLE: 11 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 12	GTS-RES CHOICE - HEAT	03	2	13.0	85.09	.00	83.39	.00	83.39
32	12 12	TOTAL RESIDENTIAL		2	13.0	85.09	.00	83.39	.00	83.39
32	12 12	GTS-COM CHOICE - HEAT	04	61	10,736.6	69,183.06	.00	67,799.38	.00	67,799.38
32	12 12	TOTAL COMMERCIAL		61	10,736.6	69,183.06	.00	67,882.77	.00	67,882.77
32	12 12	GTS-IND CHOICE - ALL	05	1	225.1	1,473.28	.00	1,443.81	.00	1,443.81
32	12 12	TOTAL		64	10,974.7	70,741.43	.00	69,326.58	.00	69,326.58

********** # OF CUSTOMERS BILLED BY COLUMBIA 64 TIMES $ .200 = 12.80

********** COLUMBIA MCF CHARGE 10,974.7 TIMES $ .050 = 548.74

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STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS550DHK
CURRENT DATE: 01/01/13

COLUMBIA CHOICE PROGRAM - DECEMBER 2012
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 12 / 2012
GAS BILLING CYCLE: 11 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	12 12	GTS-RES CHOICE - HEAT	03	1,738	15,674.3	90,749.51	.00	88,934.50	.00	88,934.50
32	12 12	GTS-RES CHOICE - NON-HEAT	05	29	35.6	206.14	.00	202.02	.00	202.02
32	12 12	TOTAL RESIDENTIAL		1,767	15,709.9	90,955.65	.00	89,136.52	.00	89,136.52
32	12 12	GTS-COM CHOICE - HEAT	04	1,011	38,066.6	220,443.66	.00	216,034.08	.00	216,034.88
32	12 12	GTS-COM CHOICE - NON-HEAT	08	20	539.6	3,124.29	.00	3,061.81	.00	3,061.81
32	12 12	TOTAL COMMERCIAL		1,031	38,606.2	223,567.95	.00	308,233.21	.00	308,233.21
32	12 12	GTS-IND CHOICE - ALL	06	3	44.2	263.92	.00	258.64	.00	258.64
32	12 12	TOTAL		2,801	54,360.3	314,787.52	.00	308,491.85	.00	308,491.85

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,801 TIMES $ .200 = 560.20

********** COLUMBIA MCF CHARGE 54,360.3 TIMES $ .050 = 2,718.02

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 02/01/13

COLUMBIA CHOICE PROGRAM - JANUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 01 / 2013
GAS BILLING CYCLE: 12 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 13	GTS-RES CHOICE - HEAT	03	3,912	58,137.9	381,962.05	.00	374,322.83	.00	374,322.83
32	01 13	GTS-RES CHOICE - NON-HEAT	05	36	91.6	575.49	.00	563.96	.00	563.96
32	01 13	TOTAL RESIDENTIAL		3,948	58,229.5	382,537.54	.00	374,886.79	.00	374,886.79
32	01 13	GTS-COM CHOICE - HEAT	04	887	99,381.0	595,760.12	.00	583,844.98	.00	583,844.98
32	01 13	GTS-COM CHOICE - NON-HEAT	08	25	376.1	2,054.28	.00	2,013.20	.00	2,013.20
32	01 13	TOTAL COMMERCIAL		912	99,757.1	597,814.40	.00	960,744.97	.00	960,744.97
32	01 13	GTS-IND CHOICE - ALL	06	3	4,911.6	28,732.86	.00	28,158.20	.00	28,158.20
32	01 13	TOTAL		4,863	162,898.2	1,009,084.80	.00	988,903.17	.00	988,903.17

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,863 TIMES $ .200 = 972.60

********** COLUMBIA MCF CHARGE 162,898.2 TIMES $ .050 = 8,144.91

RS5500MK
CURRENT DATE: 02/01/13

COLUMBIA CHOICE PROGRAM - JANUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 01 / 2013
GAS BILLING CYCLE: 12 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 13	GTS-RES CHOICE - HEAT	03	115	1,566.2	13,183.96	.00	12,920.28	.00	12,920.28
32	01 13	GTS-RES CHOICE - NON-HEAT	05	1	5.9	40.47	.00	39.66	.00	39.66
32	01 13	TOTAL RESIDENTIAL		116	1,572.1	13,224.43	.00	12,959.94	.00	12,959.94
32	01 13	GTS-COM CHOICE - HEAT	04	1	22.4	214.82	.00	210.52	.00	210.52
32	01 13	TOTAL COMMERCIAL		1	22.4	214.82	.00	13,170.46	.00	13,170.46
32	01 13	TOTAL		117	1,594.5	13,439.25	.00	13,170.46	.00	13,170.46

********** # OF CUSTOMERS BILLED BY COLUMBIA 117 TIMES $ .200 = 23.40

********** COLUMBIA MCF CHARGE 1,594.5 TIMES $ .050 = 79.73

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STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RSS500MK
CURRENT DATE: 02/01/13

COLUMBIA CHOICE PROGRAM - JANUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

J65

DIS BILLING CYCLE: 01 / 2013
GAS BILLING CYCLE: 12 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 13	GTS-RES CHOICE - HEAT	03	19,876	298,218.3	2,104,549.61	.00	2,062,458.69	.00	2,062,458.69
32	01 13	GTS-RES CHOICE - NON-HEAT	95	233	1,104.5	8,056.34	.00	7,895.20	.00	7,895.20
32	01 13	TOTAL RESIDENTIAL		20,109	299,322.8	2,112,605.95	.00	2,070,353.89	.00	2,070,353.89
32	01 13	GTS-COM CHOICE - HEAT	04	1,881	151,424.9	1,040,546.36	.00	1,019,735.77	.00	1,019,735.77
32	01 13	GTS-COM CHOICE - NON-HEAT	08	130	815.5	5,343.94	.00	5,237.11	.00	5,237.11
32	01 13	GTS-COM CHOICE - HEAT&A/C	13	2	131.2	917.09	.00	898.75	.00	898.75
32	01 13	TOTAL COMMERCIAL		2,013	152,371.6	1,046,807.39	.00	3,096,225.52	.00	3,096,225.52
32	01 13	GTS-IND CHOICE - ALL	06	5	2,900.6	17,840.62	.00	17,483.80	.00	17,483.80
32	01 13	TOTAL		22,127	454,595.0	3,177,253.96	.00	3,113,709.32	.00	3,113,709.32

*********> # OF CUSTOMERS BILLED BY COLUMBIA 22,127 TIMES $ .200 = 4,425.40

********* COLUMBIA MCF CHARGE 454,595.0 TIMES $ .050 = 22,729.75

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 02/01/13

COLUMBIA CHOICE PROGRAM - JANUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 01 / 2013
GAS BILLING CYCLE: 12 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 13	GTS-RES CHOICE - HEAT	03	48	906.2	5,091.53	.00	4,989.68	.00	4,989.68
32	01 13	GTS-RES CHOICE - NON-HEAT	05	3	22.7	117.71	.00	115.35	.00	115.35
32	01 13	TOTAL RESIDENTIAL		51	928.9	5,209.24	.00	5,105.03	.00	5,105.03
32	01 13	GTS-COM CHOICE - HEAT	04	80	10,036.0	57,472.38	.00	56,322.93	.00	56,322.93
32	01 13	GTS-COM CHOICE - NON-HEAT	08	1	18.3	111.63	.00	109.40	.00	109.40
32	01 13	TOTAL COMMERCIAL		81	10,054.3	57,584.01	.00	61,537.36	.00	61,537.36
32	01 13	TOTAL		132	10,983.2	62,793.25	.00	61,537.36	.00	61,537.36

********** # OF CUSTOMERS BILLED BY COLUMBIA 132 TIMES $ .200 = 26.40

********** COLUMBIA MCF CHARGE 10,983.2 TIMES $ .050 = 549.16

RS5500NK
CURRENT DATE: 02/01/13

COLUMBIA CHOICE PROGRAM - JANUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

OIS BILLING CYCLE: 01 / 2013
GAS BILLING CYCLE: 12 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 13	GTS-RES CHOICE - HEAT	05	2	17.5	104.46	.00	102.37	.00	102.37
32	01 13	TOTAL RESIDENTIAL		2	17.5	104.46	.00	102.37	.00	102.37
32	01 13	GTS-COM CHOICE - HEAT	04	58	13,160.7	78,559.54	.00	76,988.37	.00	76,988.37
32	01 13	TOTAL COMMERCIAL		58	13,160.7	78,559.54	.00	77,090.74	.00	77,090.74
32	01 13	GTS-IND CHOICE - ALL	06	1	361.2	2,156.00	.00	2,112.88	.00	2,112.88
32	01 13	TOTAL		61	13,539.4	80,820.00	.00	79,203.62	.00	79,203.62

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 13,539.4 TIMES $ .050 = 676.97

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500HK
CURRENT DATE: 02/01/13

COLUMBIA CHOICE PROGRAM - JANUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 01 / 2013
GAS BILLING CYCLE: 12 / 2012

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	01 13	GTS-RES CHOICE - HEAT	03	1,725	23,160.8	134,102.25	.00	131,420.19	.00	131,420.19
32	01 13	GTS-RES CHOICE - NON-HEAT	05	28	56.7	328.32	.00	321.75	.00	321.75
32	01 13	TOTAL RESIDENTIAL		1,753	23,217.5	134,430.57	.00	131,741.94	.00	131,741.94
32	01 13	GTS-COM CHOICE - HEAT	04	1,001	56,377.7	326,426.90	.00	319,898.51	.00	319,898.51
32	01 13	GTS-COM CHOICE - NON-HEAT	08	20	548.9	3,177.77	.00	3,114.22	.00	3,114.22
32	01 13	TOTAL COMMERCIAL		1,021	56,926.6	329,604.67	.00	454,754.67	.00	454,754.67
32	01 13	GTS-IND CHOICE - ALL	06	3	46.5	269.24	.00	263.85	.00	263.85
32	01 13	TOTAL		2,777	80,190.6	464,304.48	.00	455,018.52	.00	455,018.52

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,777 TIMES $ .200 = 555.40

********* COLUMBIA HCF CHARGE 80,190.6 TIMES $ .050 = 4,009.53

RS5500MK
CURRENT DATE: 03/01/13

COLUMBIA CHOICE PROGRAM - FEBRUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 02 / 2013
GAS BILLING CYCLE: 01 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 13	GTS-RES CHOICE - HEAT	03	3,879	56,286.4	369,695.61	.00	362,301.70	.00	362,301.70
32	02 13	GTS-RES CHOICE - NON-HEAT	05	36	87.5	555.95	.00	544.83	.00	544.83
32	02 13	TOTAL RESIDENTIAL		3,915	56,373.9	370,251.56	.00	362,846.53	.00	362,846.53
32	02 13	GTS-COM CHOICE - HEAT	04	891	97,391.9	581,653.61	.00	570,020.63	.00	570,020.63
32	02 13	GTS-COM CHOICE - NON-HEAT	08	25	299.7	1,637.77	.00	1,605.01	.00	1,605.01
32	02 13	TOTAL COMMERCIAL		916	97,691.6	583,291.38	.00	934,472.17	.00	934,472.17
32	02 13	GTS-IND CHOICE - ALL	06	3	4,461.7	26,100.95	.00	25,578.93	.00	25,578.93
32	02 13	TOTAL		4,834	158,527.2	979,643.89	.00	960,051.10	.00	960,051.10

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,834 TIMES $ .200 = 966.80

********** COLUMBIA MCF CHARGE 158,527.2 TIMES $ .050 = 7,926.36

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RESPONDENT: JUDY M COOPER

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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 03/01/13

COLUMBIA CHOICE PROGRAM - FEBRUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 02 / 2013
GAS BILLING CYCLE: 01 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 13	GTS-RES CHOICE - HEAT	03	114	1,476.7	12,449.30	.00	12,200.32	.00	12,200.32
32	02 13	GTS-RES CHOICE - NON-HEAT	05	1	6.8	46.65	.00	45.72	.00	45.72
32	02 13	TOTAL RESIDENTIAL		115	1,485.5	12,495.95	.00	12,246.04	.00	12,246.04
32	02 13	GTS-COM CHOICE - HEAT	04	1	16.8	161.11	.00	157.89	.00	157.89
32	02 13	TOTAL COMMERCIAL		1	16.8	161.11	.00	12,403.93	.00	12,403.93
32	02 13	TOTAL		116	1,502.3	12,657.06	.00	12,403.93	.00	12,403.93

********** # OF CUSTOMERS BILLED BY COLUMBIA 116 TIMES $ .200 = 23.20

********** COLUMBIA MCF CHARGE 1,502.3 TIMES $ .050 = 75.12

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RESPONDENT: JUDY M COOPER

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CURRENT DATE: 03/01/13

COLUMBIA CHOICE PROGRAM - FEBRUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

DIS BILLING CYCLE: 02 / 2013
GAS BILLING CYCLE: 01 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 13	GTS-RES CHOICE - HEAT	03	19,776	291,218.5	2,054,724.89	.00	2,013,630.51	.00	2,013,630.51
32	02 13	GTS-RES CHOICE - NON-HEAT	05	231	1,052.0	7,670.74	.00	7,517.32	.00	7,517.32
32	02 13	TOTAL RESIDENTIAL		20,007	292,270.5	2,062,395.63	.00	2,021,147.83	.00	2,021,147.83
32	02 13	GTS-COM CHOICE - HEAT	04	1,877	159,079.3	1,087,611.03	.00	1,065,858.95	.00	1,065,858.95
32	02 13	GTS-COM CHOICE - NON-HEAT	08	130	548.2	3,687.30	.00	3,613.58	.00	3,613.58
32	02 13	GTS-COM CHOICE - HEAT&A/C	13	2	145.8	1,019.14	.00	998.76	.00	998.76
32	02 13	TOTAL COMMERCIAL		2,009	159,773.3	1,092,317.47	.00	3,091,619.12	.00	3,091,619.12
32	02 13	GTS-IND CHOICE - ALL	06	5	2,629.8	16,372.98	.00	16,045.52	.00	16,045.52
32	02 13	TOTAL		22,021	454,673.6	3,171,086.08	.00	3,107,664.64	.00	3,107,664.64

********** # OF CUSTOMERS BILLED BY COLUMBIA 22,021 TIMES $ .200 = 4,404.20

********** COLUMBIA MCF CHARGE 454,673.6 TIMES $ .050 = 22,733.68

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PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

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CURRENT DATE: 03/01/13

COLUMBIA CHOICE PROGRAM - FEBRUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 02 / 2013
GAS BILLING CYCLE: 01 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 13	GTS-RES CHOICE - HEAT	03	48	858.3	4,818.54	.00	4,722.16	.00	4,722.16
32	02 13	GTS-RES CHOICE - NON-HEAT	05	3	18.8	96.81	.00	94.87	.00	94.87
32	02 13	TOTAL RESIDENTIAL		51	877.1	4,915.35	.00	4,817.03	.00	4,817.03
32	02 13	GTS-COM CHOICE - HEAT	04	80	10,306.2	59,561.00	.00	58,369.81	.00	58,369.81
32	02 13	GTS-COM CHOICE - NON-HEAT	08	1	43.2	263.52	.00	258.25	.00	258.25
32	02 13	TOTAL COMMERCIAL		81	10,349.4	59,824.52	.00	63,445.09	.00	63,445.09
32	02 13	TOTAL		132	11,226.5	64,739.87	.00	63,445.09	.00	63,445.09

********** # OF CUSTOMERS BILLED BY COLUMBIA 132 TIMES $ .200 = 26.40

********** COLUMBIA MCF CHARGE 11,226.5 TIMES $ .050 = 561.33

RS550MK
CURRENT DATE: 03/01/13

COLUMBIA CHOICE PROGRAM - FEBRUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 02 / 2013
GAS BILLING CYCLE: 01 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 13	GTS-RES CHOICE - HEAT	03	2	15.6	92.31	.00	90.46	.00	90.46
32	02 13	TOTAL RESIDENTIAL		2	15.6	92.31	.00	90.46	.00	90.46
32	02 13	GTS-COM CHOICE - HEAT	04	58	13,468.2	79,858.06	.00	70,260.92	.00	78,260.92
32	02 13	TOTAL COMMERCIAL		58	13,468.2	79,858.06	.00	78,351.38	.00	78,351.38
32	02 13	GTS-IND CHOICE - ALL	06	1	269.4	1,594.04	.00	1,562.16	.00	1,562.16
32	02 13	TOTAL		61	13,753.2	81,544.41	.00	79,913.54	.00	79,913.54

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 13,753.2 TIMES $ .050 = 687.66

RS5500MK
CURRENT DATE: 03/01/13

COLUMBIA CHOICE PROGRAM - FEBRUARY 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 02 / 2013
GAS BILLING CYCLE: 01 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	02 13	GTS-RES CHOICE - HEAT	03	1,711	22,644.5	126,424.58	.00	123,896.13	.00	123,896.13
32	02 13	GTS-RES CHOICE - NON-HEAT	05	28	57.5	320.91	.00	314.50	.00	314.50
32	02 13	TOTAL RESIDENTIAL		1,739	22,702.0	126,745.49	.00	124,210.63	.00	124,210.63
32	02 13	GTS-COM CHOICE - HEAT	04	994	55,230.4	308,167.58	.00	302,004.33	.00	302,004.33
32	02 13	GTS-COM CHOICE - NON-HEAT	08	20	537.1	3,002.41	.00	2,942.36	.00	2,942.36
32	02 13	TOTAL COMMERCIAL		1,014	55,767.5	311,169.99	.00	429,157.32	.00	429,157.32
32	02 13	GTS-IND CHOICE - ALL	06	3	61.2	351.71	.00	344.67	.00	344.67
32	02 13	TOTAL		2,756	78,530.7	438,267.19	.00	429,501.99	.00	429,501.99

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,756 TIMES $ .200 = 551.20

********** COLUMBIA MCF CHARGE 78,530.7 TIMES $ .050 = 3,926.54

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
ATTACHMENT A PAGE 139 OF 145
RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 03/29/13

COLUMBIA CHOICE PROGRAM - MARCH 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : CONSTELLATION ENERGY GAS CHOICE

DIS BILLING CYCLE: 03 / 2013
GAS BILLING CYCLE: 02 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 13	GTS-RES CHOICE - HEAT	03	3,852	52,158.2	342,553.02	.00	335,701.98	.00	335,701.98
32	03 13	GTS-RES CHOICE - NON-HEAT	05	36	74.0	472.99	.00	463.51	.00	463.51
32	03 13	TOTAL RESIDENTIAL		3,888	52,232.2	343,026.01	.00	336,165.49	.00	336,165.49
32	03 13	GTS-COM CHOICE - HEAT	04	886	91,809.4	548,024.50	.00	537,064.14	.00	537,064.14
32	03 13	GTS-COM CHOICE - NON-HEAT	08	25	357.1	1,944.99	.00	1,906.10	.00	1,906.10
32	03 13	TOTAL COMMERCIAL		911	92,166.5	549,969.49	.00	875,135.73	.00	875,135.73
32	03 13	GTS-IND CHOICE - ALL	06	3	4,112.8	24,059.88	.00	23,578.68	.00	23,578.68
32	03 13	TOTAL		4,802	148,511.5	917,055.38	.00	898,714.41	.00	898,714.41

********** # OF CUSTOMERS BILLED BY COLUMBIA 4,802 TIMES $ .200 = 960.40

********** COLUMBIA MCF CHARGE 148,511.5 TIMES $ .050 = 7,425.58

RS5500MK
CURRENT DATE: 03/29/13

COLUMBIA CHOICE PROGRAM - MARCH 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : GATEWAY ENERGY SERVICES CORP.

DIS BILLING CYCLE: 03 / 2013
GAS BILLING CYCLE: 02 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 13	GTS-RES CHOICE - HEAT	03	113	1,425.5	12,009.59	.00	11,769.40	.00	11,769.40
32	03 13	TOTAL RESIDENTIAL		113	1,425.5	12,009.59	.00	11,769.40	.00	11,769.40
32	03 13	GTS-COM CHOICE - HEAT	04	1	18.8	180.29	.00	176.68	.00	176.68
32	03 13	TOTAL COMMERCIAL		1	18.8	180.29	.00	11,946.08	.00	11,946.08
32	03 13	TOTAL		114	1,444.3	12,189.88	.00	11,946.08	.00	11,946.08

********** # OF CUSTOMERS BILLED BY COLUMBIA 114 TIMES $ .200 = 22.80

********** COLUMBIA MCF CHARGE 1,444.3 TIMES $ .050 = 72.22

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS550OMK
CURRENT DATE: 03/29/13

COLUMBIA CHOICE PROGRAM - MARCH 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : COLUMBIA RETAIL ENERGY

DIS BILLING CYCLE: 03 / 2013
GAS BILLING CYCLE: 02 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 13	GTS-RES CHOICE - HEAT	03	19,655	268,392.7	1,893,762.79	.00	1,855,887.73	.10-	1,855,887.73
32	03 13	GTS-RES CHOICE - NON-HEAT	05	227	977.2	7,130.20	.00	6,987.54	.00	6,987.54
32	03 13	TOTAL RESIDENTIAL		19,882	269,369.9	1,900,892.99	.00	1,862,875.27	.10-	1,862,875.27
32	03 13	GTS-COM CHOICE - HEAT	04	1,868	134,495.1	906,734.35	.00	888,599.52	.00	888,599.52
32	03 13	GTS-COM CHOICE - NON-HEAT	08	130	529.9	3,553.26	.00	3,482.26	.00	3,482.26
32	03 13	GTS-COM CHOICE - HEATRA/C	13	2	141.3	987.69	.00	967.93	.00	967.93
32	03 13	TOTAL COMMERCIAL		2,000	135,166.3	911,275.30	.00	2,755,924.98	.10-	2,755,924.98
32	03 13	GTS-IND CHOICE - ALL	06	5	2,705.9	16,718.78	.00	16,384.41	.00	16,384.41
32	03 13	TOTAL		21,887	407,242.1	2,828,887.07	.00	2,772,309.39	.10-	2,772,309.39

********** # OF CUSTOMERS BILLED BY COLUMBIA 21,887 TIMES $ .200 = 4,377.40

********** COLUMBIA MCF CHARGE 407,242.1 TIMES $ .050 = 20,362.11

RS5500HK
CURRENT DATE: 03/29/13

COLUMBIA CHOICE PROGRAM - MARCH 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : KENTUCKY UNITED ENERGY, LLC

DIS BILLING CYCLE: 03 / 2013
GAS BILLING CYCLE: 02 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 13	GTS-RES CHOICE - HEAT	03	48	773.3	4,314.15	.00	4,227.86	.00	4,227.86
32	03 13	GTS-RES CHOICE - NON-HEAT	05	3	16.7	85.77	.00	84.05	.00	84.05
32	03 13	TOTAL RESIDENTIAL		51	790.0	4,399.92	.00	4,311.91	.00	4,311.91
32	03 13	GTS-COM CHOICE - HEAT	04	80	7,564.3	43,683.55	.00	42,809.87	.00	42.809.87
32	03 13	GTS-COM CHOICE - NON-HEAT	08	1	49.1	299.51	.00	293.52	.00	293.52
32	03 13	TOTAL COMMERCIAL		81	7,613.4	43,983.06	.00	47,415.30	.00	47,415.30
32	03 13	TOTAL		132	8,403.4	48,382.98	.00	47,415.30	.00	47,415.30

********** # OF CUSTOMERS BILLED BY COLUMBIA 132 TIMES $ .200 = 26.40

********** COLUMBIA MCF CHARGE 8,403.4 TIMES $ .050 = 420.17

RS550OMK
CURRENT DATE: 03/29/13

COLUMBIA CHOICE PROGRAM - MARCH 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : MXENERGY

DIS BILLING CYCLE: 03 / 2013
GAS BILLING CYCLE: 02 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 13	GTS-RES CHOICE - HEAT	03		35.1	269.24	.00	263.86	.00	263.86
32	03 13	TOTAL RESIDENTIAL			35.1	269.24	.00	263.86	.00	263.86
32	03 13	GTS-COM CHOICE - HEAT	04		.3-	1.59-	.00	1.56-	.00	1.56-
32	03 13	TOTAL COMMERCIAL			.3-	1.59-	.00	262.30	.00	262.30
32	03 13	TOTAL			34.8	267.65	.00	262.30	.00	262.30

********** # OF CUSTOMERS BILLED BY COLUMBIA 0 TIMES $ .200 = .00

********** COLUMBIA MCF CHARGE 34.8 TIMES $ .050 = 1.74

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RESPONDENT: JUDY M COOPER

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COLUMBIA CHOICE PROGRAM - MARCH 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : STAND ENERGY CORPORATION

DIS BILLING CYCLE: 03 / 2013
GAS BILLING CYCLE: 02 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 13	GTS-RES CHOICE - HEAT	03	2	11.0	65.09	.00	63.79	.00	63.79
32	03 13	TOTAL RESIDENTIAL		2	11.0	65.09	.00	63.79	.00	63.79
32	03 13	GTS-COM CHOICE - HEAT	04	58	12,588.8	74,646.40	.00	73,153.46	.00	73,153.46
32	03 13	TOTAL COMMERCIAL		58	12,588.8	74,646.40	.00	73,217.25	.00	73,217.25
32	03 13	GTS-IND CHOICE - ALL	06	1	416.9	2,466.79	.00	2,417.45	.00	2,417.45
32	03 13	TOTAL		61	13,016.7	77,178.28	.00	75,634.70	.00	75,634.70

********** # OF CUSTOMERS BILLED BY COLUMBIA 61 TIMES $ .200 = 12.20

********** COLUMBIA MCF CHARGE 13,016.7 TIMES $ .050 = 650.84

PSC CASE NO. 2013-00167
STAFF SET 2 DR NO. 19 (e)
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RESPONDENT: JUDY M COOPER

RS5500MK
CURRENT DATE: 03/29/13

COLUMBIA CHOICE PROGRAM - MARCH 2013
COLUMBIA GAS OF KENTUCKY, INC.
MARKETER NAME : VOLUNTEER ENERGY SERVICES

DIS BILLING CYCLE: 03 / 2013
GAS BILLING CYCLE: 02 / 2013

CO	MO YR	NAME	REVENUE CLASS	NUMBER OF CUSTOMERS	THOUSAND CUBIC FEET	MARKETER REVENUE	100% PAY TO MKT	PURCHASED A/R	NON GUARANTEED	TOTAL MKT PAYMENT
32	03 13	GTS-RES CHOICE - HEAT	03	1,700	21,004.7	116,011.56	.00	113,691.34	.00	113,691.34
32	03 13	GTS-RES CHOICE - NON-HEAT	05	28	55.2	305.14	.00	299.04	.00	299.04
32	03 13	TOTAL RESIDENTIAL		1,728	21,059.9	116,316.70	.00	113,990.38	.00	113,990.38
32	03 13	GTS-COM CHOICE - HEAT	04	989	50,753.4	280,263.30	.00	274,657.98	.00	274,657.98
32	03 13	GTS-COM CHOICE - NON-HEAT	08	20	563.8	3,116.69	.00	3,054.36	.00	3,054.36
32	03 13	TOTAL COMMERCIAL		1,009	51,317.2	283,379.99	.00	391,702.72	.00	391,702.72
32	03 13	GTS-IND CHOICE - ALL	06	3	36.0	200.50	.00	196.49	.00	196.49
32	03 13	TOTAL		2,740	72,413.1	399,897.19	.00	391,899.21	.00	391,899.21

********** # OF CUSTOMERS BILLED BY COLUMBIA 2,740 TIMES $ .200 = 548.00

********** COLUMBIA MCF CHARGE 72,413.1 TIMES $ .050 = 3,620.66

**COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013**

20. Refer to Volume 9 of the application, the Direct Testimony of Eric T. Belle. Explain how many miles of priority pipe is represented by the $14.2 million anticipated to be spent in 2013 and the $12.2 million to be spent, by year, 2014 through 2016.

Response:

Columbia's expectation is to retire approximately 28.4 miles of priority pipe and associated services given the anticipated spend of $14.2 million of AMRP related projects. Columbia has not made final decisions on projects that will be completed in 2014 through 2016.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

21. Refer to Volume 9 of the application, the Direct Testimony of William J. Gresham ("Gresham Testimony"), page 8.

a. Explain why 20 years was chosen as the length of time over which to estimate normal weather.

b. State the source of the climate data used for the weather normalization.

c. Either indicate the location in the record of the weather normalization performed to estimate normal sales volumes, or provide the weather normalization analysis. The response should include an explanation of the methodology, which customer classes' sales volume are weather-normalized, assumptions made and the basis for those assumptions, and an electronic version of the weather-normalization analysis with the formulas intact and unprotected and all rows and columns accessible.

Response:

a. As noted in the testimony, normal weather is set to the average of the 20 years ended 2012, which represents an update to the definition of weather used in the billing determinants underlying current rates, the 20 years ended 2008. When the 20 year average was originally proposed, data was presented showing that the 20 year average was a superior measure based on a representation of future weather over a defined period of time.

b. No weather normalization has been presented in this filing. For the weather normalization presented in this response, the source of the data is the National Weather Service weather stations for Huntington, WV and Lexington, KY provided by a weather vendor.

c. For the residential and commercial classes, actual billing month sales per customer is separated into base load and temperature-sensitive load. Temperature-sensitive load is then scaled by the ratio of normal to actual heating degree days ("HDD") to derive normal temperature-sensitive load per customer. The ratio is limited to a maximum of 1.5 for the months of June and September because there have been occurrences when a small denominator (very few actual HDD) has resulted in an unrealistic normal value. The normal temperature-sensitive load per customer is then added to the base load per customer to arrive at the normal sales per customer. This value is then multiplied by the customer count to derive the normal sales volume.

For calculation of base load, the normalization procedure assumes no heat load in July and August. For September, no heat load is assumed when total load per customer per day is less than July and/or August total load per customer per day. The base load per customer per day is calculated by taking the average of the two lowest observed values from the months of July through September.

For each month, the base load per customer equals the lesser of the base load per customer per day multiplied by the days in the billing cycle or the monthly total load per customer. Once base load per customer is determined, heat load per customer is calculated. Heat load per customer equals the total load per customer minus the base load per customer. The heat load per customer is normalized by multiplying by a ratio of Normal HDD to Actual HDD. Finally, normal load per customer is calculated by adding the base load per customer to the normal heat load per customer. A total monthly normalized volume is generated by multiplying monthly customers by the monthly normal load per customer.

An electronic version is supplied in file on the separate CD labeled "Staff 2021.xlsx."

Columbia Gas of Kentucky - Weather Normalization

Residential

		Actual		Actual Vol/Cus			Normal Vol/Cus		Weather		Volume	Calculation Area					Billing
		Volume	Customers	Total	Base	TS	TS	Total	HDD	HDDN	Normal	Base Vol/Cus	Base Vol/Cus/Day	Base Vol/Cus/Day			Days
2012	1	1,553,982	121,257	12.8	1.1	11.7	13.4	14.5	859	981	1,756,172			0.032	2012	1	33.10
2012	2	1,438,229	121,261	11.9	1.0	10.9	12.8	13.8	774	909	1,668,798				2012	2	29.52
2012	3	1,032,599	121,121	8.5	1.0	7.6	9.9	10.8	544	710	1,312,417				2012	3	29.38
2012	4	393,169	120,207	3.3	1.0	2.3	4.1	5.1	247	440	607,682				2012	4	30.38
2012	5	295,505	119,550	2.5	1.0	1.5	1.8	2.7	168	197	326,467				2012	5	29.90
2012	6	145,204	118,913	1.2	1.0	0.2	0.3	1.3	32	52	158,482				2012	6	30.71
2012	7	120,485	118,227	1.0	1.0	-		1.0			120,485	1.02	0.033		2012	7	30.48
2012	8	110,628	117,884	0.9	0.9	-		0.9			110,628	0.94	0.032		2012	8	29.76
2012	9	122,262	117,792	1.0	1.0	0.0	0.0	1.0	14	6	119,037	1.04	0.034		2012	9	30.48
2012	10	218,102	118,363	1.8	1.0	0.9	0.6	1.6	161	111	185,794				2012	10	29.67
2012	11	655,546	119,541	5.5	1.0	4.5	3.6	4.6	457	368	550,388				2012	11	29.76
2012	12	1,097,183	120,446	9.1	1.0	8.1	8.6	9.7	668	714	1,164,077				2012	12	32.14
		7,182,894		59.6				67.0			8,080,427						

Commercial

		Volume	Customers	Total	Base	TS	TS	Total	HDD	HDDN	Normal	Base Vol/Cus	Base Vol/Cus/Day	Base Vol/Cus/Day			Days
2012	1	1,153,553	14,065	82.0	22.7	59.3	67.8	90.4	859	981	1,272,093			0.685	2012	1	33.095238
2012	2	1,077,674	14,064	76.6	20.2	56.4	66.2	86.5	774	909	1,216,022				2012	2	29.52381
2012	3	799,872	14,031	57.0	20.1	36.9	48.1	68.3	544	710	957,766				2012	3	29.380952
2012	4	466,895	13,943	33.5	20.8	12.7	22.6	43.4	247	440	604,947				2012	4	30.380952
2012	5	381,520	13,853	27.5	20.5	7.1	8.3	28.8	168	197	398,384				2012	5	29.904762
2012	6	309,508	13,763	22.5	21.0	1.4	2.2	23.2	32	52	319,455				2012	6	30.714286
2012	7	298,619	13,732	21.7	21.7	-		21.7			298,619	22	0.714		2012	7	30.47619
2012	8	283,038	13,683	20.7	20.7	-		20.7			283,038	21	0.695		2012	8	29.761905
2012	9	281,175	13,664	20.6	20.6	-	-	20.6	14	6	281,175	21	0.675		2012	9	30.47619
2012	10	382,873	13,708	27.9	20.3	7.6	5.2	25.6	161	111	350,496				2012	10	29.666667
2012	11	642,625	13,863	46.4	20.4	26.0	20.9	41.3	457	368	572,525				2012	11	29.761905
2012	12	891,718	13,968	63.8	22.0	41.8	44.7	66.7	668	714	931,942				2012	12	32.142857
		6,969,070		500.3				537.1			7,486,462						

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

22. Refer to page 11, line 5 of the Gresham Testimony. Clarify whether the reduction in residential customer usage was 1.2 percent annually 2007 through 2012, or 1.2 percent for the five-year period

Response:

The reduction is the compound average growth rate for the period.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

23. Refer to the Gresham Testimony, pages 11-12, where Mr. Gresham discusses the factors that have caused the reduction in customer usage.

a. Mr. Gresham identifies the reduction in customer usage over the past 10 years as "structural conservation" that is "independent of trends in residential natural gas prices." Explain whether Mr. Gresham believes the larger decrease in usage during the first half of the past 10 years, a period he indicates was marked by rising prices, compared to the smaller decrease over the second half of the past 10 years, a period he indicates was marked by falling prices, was entirely independent of trends in natural gas prices.

b. Near the end of this section on page 12 of his testimony, Mr. Gresham discusses appliance choice (gas versus electric) and states that this will be particularly relevant in Kentucky, where electricity rates are low. Describe the extent to which Mr. Gresham's conclusions regarding natural gas usage reflect that, during the past five years, when residential gas prices were falling, residential electricity prices in Kentucky increased by an average of approximately 20 percent.

Response:

a. While structural conservation is at play in both periods, there was certainly a price response in the period of rising prices. While this point was not clear on page 11, it was indicated on page 12, "Annual conservation increased significantly with the large price increases that occurred in the winters of 2000-2001, 2004-2005, and 2005-2006."

b. The U.S. Energy Information Administration ("EIA") reports that Kentucky has the fourth lowest electricity rates of the 50 States and the District of Columbia, EIA Report "State Electricity Profiles", January 2012. To the extent that electricity prices are relevant in choosing gas appliances, the incentive to choose electric appliances is greater in Kentucky than in most other states.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

24. Refer to the Volume 9 of the application, Direct Testimony of Paul R. Moul ("Moul Testimony"). Provide the American Gas Foundation study referenced on page 8.

Response:

The referenced American Gas Foundation document is attached.

American Gas Foundation

Regulatory Policy of Return on Equity

Review and Analysis of the Natural Gas Utility Sector

December 9, 2008

American Gas Foundation
400 North Capitol St., NW
Washington, DC 20001
www.gasfoundation.org

Regulatory Policy of Return on Equity

Review and Analysis of the Natural Gas Utility Sector

December 9, 2008

Prepared for the American Gas Foundation by:

NAVIGANT CONSULTING

Navigant Consulting
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Suite 1900
Houston, TX 77010

DISCLAIMER

American Gas Foundation

Founded in 1989, the American Gas Foundation is a 501(c)(3) organization that focuses on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas. For more information, please visit www.gasfoundation.org or contact Jay Copan, executive director, at (202) 824-7020 or jcopan@gasfoundation.org.

Navigant Consulting

Navigant Consulting, Inc. is a specialized, international consulting firm with industry expertise and integrated solutions to assist companies and their legal counsel in enhancing stakeholder value, improving operations, and addressing conflict, performance and risk related challenges. The Company focuses on industries undergoing substantial regulatory or structural change, including energy and many others. Navigant has offices in over 40 cities in North America, Europe and Asia.

Navigant Consulting's Energy Practice focuses on helping clients strengthen their enterprises by increasing performance, opportunity and growth. The Company's professionals deliver expertise includes understanding of regulatory processes, pricing, supply and demand dynamics, market design, fuel sourcing, financing, technologies and operations. Navigant Consulting's natural gas modeling and forecasting practice has extensive experience advising investors and developers in facilities for electric power generation, liquefied natural gas, pipelines and gas storage as to the forward-looking expectation for industry supply, demand, and pricing.

Table of Contents

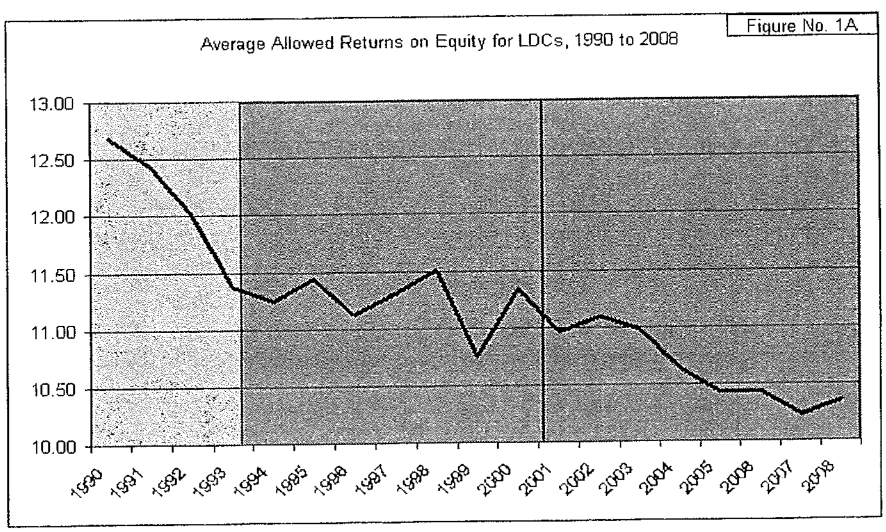
I. Executive Summary

The continued success of the utility sector to deliver natural gas safely and reliably depends upon a strong and viable infrastructure that will meet growing local distribution company (LDC) customer demands. The infrastructure development needed to address new and aging infrastructure relies heavily upon the ability of the industry to attract strong capital investment. As such, the American Gas Foundation (AGF) engaged Navigant Consulting Inc. (NCI) to examine the current processes utilized by the state public utility commissions to determine allowed returns on equity (RoE) for natural gas utilities in an effort to determine if the RoE rates being approved and established are adequate and sufficient to address U.S. pipeline and distribution infrastructure needs.

Given the diversity of state jurisdictions and policies, the effort undertaken for this study examines all state decisions over an extended period of time and relies upon statistical examinations of that large population of cases, informed by extensive interviews with financial analysts and senior industry executives, to identify and interpret trends and reasons for those trends and determine whether there is a perceived problem within the financial community. The core question posed by the study's mission statement and objectives, the impact of RoE decisions and policy on LDC infrastructure adequacy, is largely addressed through the interview process. This AGF study is intended to be an examination, and evaluation of the issues. While it observes various trends, impacts, and reasons for those impacts, it is up to other efforts to support the need for specific changes in individual proceedings. The study is intended as a backdrop to inform such efforts.

Background -- Trend in Allowed Returns

The phenomenon of steady declines in allowed LDC returns is clear, based upon an examination of some 377 PUC decisions nationwide, over the period from 1990 through 2008. In particular, the most recent period, from 2000 through 2008, has seen a steady decline from the mid 11 percent range to the low 10 percent range, with several recent decisions falling below 10 percent.



Further, the study analysis shows that this perceived decline was pervasive, with the overall distribution of returns moving to the lower levels. It also shows that there is a growing gap between the actual LDC equity ratios and the equity ratios that are actually recognized in rates – as is explained more fully in the study. Therefore, either approximately $2 billion of LDC equity investment is treated as if it is financed with debt, thus significantly reducing the recognized cost of that investment recovered in rates, or LDCs must adopt a higher debt level, which would increase financial risk. The LDC industry is generally facing RoE decisions and policies that result in returns around and below the 10 percent level.

Summary of Findings

Multiple interviews were conducted with financial analysts (both equity and debt) and senior industry executives (primarily chief executive officers of either LDC holding companies or the LDC subsidiaries of those holding companies). To encourage the candor of those interviews and to avoid singling out specific companies or jurisdictions, the interviews are summarized and explained in the body of this study, without attribution to specific individuals. Observations and conclusions include:

- Equity analysts expressed concern that when allowed returns drift below 10 percent, financial markets see that as a "red flag" that could turn substantial investment away from the industry. This risk is particularly valid now, according to the analysts, since changes in the population of large investors toward a greater weight of hedge funds and private equity firms allows large blocks of money to move much faster than in the past in departing from an industry.

- Equity analysts also stressed that if there are other indications of a favorable regulatory environment, one of mutual trust with collaborative development of comprehensive service and rate structures by the LDC and the regulator, the perception that low allowed returns indicate an unfavorable regulatory environment is largely ameliorated. However, there is a strong concern that a jurisdiction will work to develop such balanced, collaborative approaches, use that as a basis for low returns, and then, over time, erode the quality of the balanced approaches without revisiting return. This concern strongly validates the importance of open and honest dialogue between the utilities and their regulators, such that a mutuality of trust can stay in place long-term.

- Uniformly, the executives running LDCs are committed to safety and reliability of service, and thus will strive to invest what is required to maintain those objectives, as long as they are in the LDC business. However, low returns create incentives for them to avoid discretionary investment, and for their holding companies to exit the LDC business.

- It is only in jurisdictions where allowed returns have remained at higher levels more consistent with history, or where the LDC and its regulator have developed collaborative, more holistic approaches to services and rates supplanting traditional usage-based and cost-based regulation, that these incentives are not creating negative pressure on investment.

- Except for the jurisdictions where returns have remained higher, or where other arrangements have successfully supplanted more traditional regulation, the LDCs are experiencing increasing difficulty in competing for capital. The measure of such difficulty is not the relationship to debt cost, but the relationship to alternative equity investments.

- To date, much investment and even some merger and acquisition consolidation of the LDC industry have continued, but the continuation does not mean there is not a deep concern over allowed returns – rather, the various businesses are seizing opportunities as they present themselves, with the expectation that currently depressed allowed returns are a short-term phenomenon – the managers trust the system to "self-correct" over time. If that turns out not to be the case, the risk the industry and regulators run is a fundamental loss of trust in the regulatory system, one that would have a strongly negative impact on investment.

- Thus, although low returns have created a negative pressure on investment in LDC infrastructure, little impact has been seen to date. Public markets for capital have still been accessible for LDCs, in the opinion of the analysts and senior executives because of two factors: (1) the faith in the regulatory system recited above; and (2) the currently favorable tax treatment of dividends. However, continuing downward trends in allowed returns undermine the first rationale, and political uncertainty undermines the second. In addition, the recent large concentration of equity investment in such vehicles as hedge funds is expected to make financial markets quicker to react negatively if the current negative perceptions of LDC investment persist. In short, the threat to infrastructure adequacy is a looming threat, exacerbated by low returns, a threat that could be ameliorated by some corrective action.

- Various rate-design changes, in particular "decoupling," can provide some stabilization of LDC revenues, if properly applied. However, there is concern that regulators accord inordinate weight to these mechanisms' impact on risk when setting returns. Further, it is believed that many times there is a potential double-counting of the effect, since regulators apply a decrement to returns developed by reference to proxy companies that have similar de-risking mechanisms. Uniformly, the interviewees believed such decrements were ill-advised and unfair.

- At the same time, other risks of the LDC business have been increasing–specifically unfunded government mandates, precipitous run-up in the cost of critical materials such as steel and in the cost of contract labor, the regulatory risk of cost disallowance, especially in periods of rapid gas-cost increase, and asymmetric regulation of uncollected gas cost (e.g., paying interest on overcollections but collecting no interest on undercollections). Additionally, in the competitive, unbundled world of today's interstate pipelines, the risk of bypass for LDCs' highest-volume loads is pervasive. Thus, to the extent that decoupling might tend to stabilize revenues and thus ameliorate that area of risk, these other evolving risks offset or even reverse that effect. Further, unlike the revenue volatility addressed by decoupling (which volatility could go either way – reducing earnings or increasing earnings, depending on weather), these evolving risks are "one-way," strictly acting to the detriment of the LDC.

- The debt rating community is generally not deeply concerned with allowed return on equity, unless it gets low enough to threaten required debt coverage. That coverage cushion may be relatively smaller if the whole regulatory scheme enhances stability of revenues.

- However, the debt analysts do become concerned when allowed RoE drops to a level that forces company management to reorient investment into riskier areas to meet Wall Street expectations of growth. In other words, the allowed returns for the LDC must meet a risk-adjusted comparison with alternative investments, or the company's stockholders will tend to push reorientation to the point that its overall revenue profile becomes more volatile, and thus its corporate debt becomes less secure.

- There is much more depth in these and other observations in the body of the AGF Study. Overall, it is fair to say that there is widespread concern over the industry's ongoing ability to raise and retain capital. Generally senior executives feel that in the current market, returns below 10 percent are very problematic, that returns in the mid-10s are adequate to keep the businesses on an even keel, but not to win contested capital in competition with investments in other businesses with similar risk, and that returns in the low 11s, e.g., 11.25, can generally reach risk-adjusted parity with the investments with which LDCs must compete for capital.

- Clearly, the concerns raised by both financial analysts and senior executives in the industry have grown a great deal in importance in the current credit and financial turmoil. The rapidly evolving difficulties in raising all types of capital, both debt and equity, would suggest that any negatively perceived factor, such as inadequate or declining allowed rates of return, could exacerbate an already problematic situation in funding new infrastructure.

Reasons for Declines in Allowed Return

The study examines the two dominant methodologies used to set allowed RoE: Discounted Cash Flow (DCF) and the Capital Asset Pricing Model (CAPM), along with Equity Risk Premium (ERP), of which CAPM is a variation.

Very simply, the fundamental inputs to these longstanding methodologies have declined, so the resulting indicated rates of return have declined. In the case of DCF, the decline has been driven by reduced growth rates among proxy companies. In the case of CAPM (and ERP), the decline has been driven directly by the decline in interest rates over the last decade. While it is easy to identify the reasons the longstanding formulae are yielding lower results, the more difficult question is whether this effect highlights what may be infirmities in the methodologies, infirmities that were less apparent during periods of higher growth and higher interest rates.

This study explains the fundamental theory and operation of DCF and CAPM, with some generic calculations of the impact at today's input numbers. These calculations are based on a sample group of twelve proxy LDCs extracted from PUC staff testimony in a recent rate case (both the state and the LDCs are unnamed, to avoid any prejudicial reference to individual situations). Both DCF and CAPM yield average indicated returns on equity of 9.7 percent, over the twelve proxy companies. However, while the average is equal as between the methods, individual results varied by as much as 460 basis points.

These examples were useful in analyzing some of the issues presented by the application of DCF and CAPM.

- There was very wide diversity in the outcome indicated returns among the companies in the sample group: 740 basis points from the high to the low under DCF, and 630 basis points from the high to the low under CAPM. Given that the twelve-company proxy group consists of relatively similar LDCs, it is difficult to see a justification for these wide swings.

- For both DCF and CAPM, there is an inherent circularity in the use of proxy groups, in that if all the companies in the proxy group are similarly regulated, the Wall Street expectations for all of them will be similar – however, there is no test as to whether this uniform expectation is in fact adequate to compete for capital with non-LDC businesses having similar risks.

- As for DCF, there is a test performed in this study to determine whether the end result meets its own premises – that is, the DCF result is based on an investor expectation of a specific rate of growth in earnings and book value per share. It is demonstrated that, if retained earnings are the primary driver of such growth, the use of the DCF return as an allowed RoE does not generate enough cash to pay required dividends and still generate the assumed growth.

- The 9.7 percent average indicated RoE would generate only 3.5 percent and 3.4 percent growth in book value and earnings per share, respectively.
- However, within the development of the 9.7 percent, there is a determination that investor-expected growth is 6.4 percent, leaving a 3 percent deficiency in the growth rate.

- In the case of CAPM, as noted it is just a modified version of ERP – a fixed equity risk premium over risk-free debt is assumed to exist, regardless of the current interest-rate regime. The CAPM refinement to this assumption is merely to modify that fixed risk premium by multiplying it by a "Beta" factor to reflect a particular stock's volatility vs. the stock market at large.

- The open issue regarding either CAPM or ERP is whether a fixed equity risk premium is a valid assumption in the first place – many experts expect that risk premium to expand at low interest rates and contract at high interest rates.

- In other words, a broad school of thought believes the relationship between the cost of equity and the cost of debt is partial and tenuous. Even in Canada, where RoE is set by a formula tracking corporate bond rates, the "elasticity" or relationship between changes in the interest rate and changes in the RoE is less than one, presently 75 percent. Meanwhile, the Canadian gas industry strongly believes it should be even lower, probably about 50 percent.

- The result is that CAPM or ERP will give low RoE when interest rates are low, without taking account of the equity-vs.-equity competition discussed earlier.

Potential Adjustments

This study explores several potential adjustments to the return-setting process that could work to restore allowed RoE to the levels thought by the industry and analysts to be sufficient. These potential adjustments include:

- Broadening the proxy groups to reach beyond LDCs who are regulated under the same rules and methodologies as the company being examined. This would address the circularity of current proxy approaches.

- Using FERC decisions as a benchmark, recognizing that historically LDC RoE has generally been approximately 125 basis points lower than the RoE allowed to interstate pipelines. Maintaining this historic gap would help equilibrate the competition for capital between the LDC and the pipeline in the same corporate family.

- Considering variations on CAPM, such as the Fama-French Three Factor Model, which brings into the equation small-cap and high-growth companies to attempt to gain a clearer picture of investor expectations than is yielded by CAPM's averages.

- Restoring the growth deficiency identified under DCF. In the example, this would bring the indicated return up to 12.7 percent if 100 percent of the deficiency were restored. This is somewhat higher than the 11.25 percent to 11.50 percent the senior executives indicated is needed in the current environment, so methods could be explored to restore a portion of the deficiency, still assuming that some growth might come from other sources.

An overarching point is that regardless of the types of adjustments that might be sought, the industry must establish a credible case that real public damage can result from inadequate returns, in the form of inadequate investment, lost efficiencies, etc. While RoE decisions may be challenged in court, real ongoing relief requires a cooperative relationship with regulators that acknowledges the problem and indentifies the solutions.

In the case of an issue such as RoE, this is difficult, since any remedy means higher rates for consumers. However, the ultimate effect of allowed RoE being below the level required by investors may be a lessened ability to maintain and develop systems and this may result in inefficient natural gas service. Thus, substantial attention must be paid by the industry to establishing and maintaining the necessary credibility, through informal outreach, public presentations, and education such as this study.

II. Introduction

A. Background

Evaluating LDC allowed rates of return is a significantly different exercise than the review of pipeline allowed rates of return. Pipelines are subject to a single decision maker, the Federal Energy Regulatory Commission (FERC), while LDCs are subject to the jurisdiction of fifty different state public utility commissions (PUCs), and in some cases to regulation by the municipalities that they serve. In short, the approaches and the results among PUC decisions are much more diverse than is the case at the FERC, and the relationships between LDCs and their state regulators are more direct than those funneled through a central national venue.

Accordingly, this AGF study avoids singling out particular jurisdictions or companies, rather working to gain a common view across the industry of those factors or issues that do exhibit some commonality. Additionally, in part because there is not a single decision maker in the national LDC arena and in part because of the nature of AGF's mission, the AGF Study is intended as an examination of the facts and opinions it has elicited.

B. Process and Structure of Study

The body of the study consists of three major sections, Sections III through V.

In Section III, a quantitative analysis is combined with extensive interviews with financial community analysts and industry senior executives, to determine whether a pervasive problem exists or is emerging as to the rates of return being allowed to LDCs, and if there is such a problem what its implications might be for public policy. Heavy emphasis is placed here on the importance of credibility to the extent the industry claims the existence of a problem, with thoughts elicited from the interview process as to how such credibility might be enhanced.

In Section IV, to the extent that any problems in levels or trends in allowed returns have been identified in Section III, the processes and approaches used by PUCs that lead to such deficiencies or trends are identified and examined. Are there chronic forces at play that will result in long-term declines in allowed returns, or are current levels a short-term phenomenon?

Section V addresses possible changes or adjustments in observed processes, to the extent such changes or adjustments might be needed to respond to chronic issues that are identified in the study.

It is fair to say that Section III, grounded in observations of the rates of return actually being allowed and in the perspectives of the financial analysts who evaluate those companies and the senior executives of the regulated companies, is by far the most important aspect of this study. Developing the case that allowed returns have declined, that the levels at which they are being allowed are becoming problematic for the regulated companies, and that their problems will eventually become the public's problem, is critical as a threshold that must be crossed prior to questioning the specifics or the mechanics of the return-setting process.

III. LDC Allowed Rates of Return

As noted, the determination as to whether there has been a decline in allowed rates of return on equity and the development of a case as to whether such declines have long-term public-policy implications have been approached both quantitatively, through the measurement of allowed returns over time, and qualitatively, through an extensive series of industry interviews. Section A, below, presents the quantitative analysis. Section B then uses the results of the interviews to interpret the quantitative data.

A. Allowed LDC Rates of Return over Time

In order to measure changes in allowed returns on equity over the past several years, NCI gathered all reported LDC rate cases that were resolved from 1990 through mid-2008.[1] In total nationwide, there were 532 LDC rate cases closed during that 18.5 year period, spread fairly evenly over the many regions of the country. Of those 532 rate cases, many of them were resolved such that there was no stated rate of return on equity, usually as the result of a settlement. Accordingly, there were a total of 377 decisions in which a rate of return on equity was approved by the LDC's regulator. These 377 data points are broadly spread over the 18.5 year period examined, and thus give a reasonably clear picture of the trends that have emerged in state regulation of LDCs.

The NCI analysis of these trends is conducted in two parts. First, simple averages of the allowed returns have been calculated for each year in the 18.5 year period. These will be presented in Figure No. 1A, with an amplified view of the results for the most recent period, 2000 through 2008 in Figure No. 1B.

Then, recognizing that averages over diverse groups of data points might not tell the whole story, the progression of the distribution of returns is analyzed, for the Figure No. 1B period from 2000 through 2008. This progression is set forth in Figure Nos. 2A through 2C.

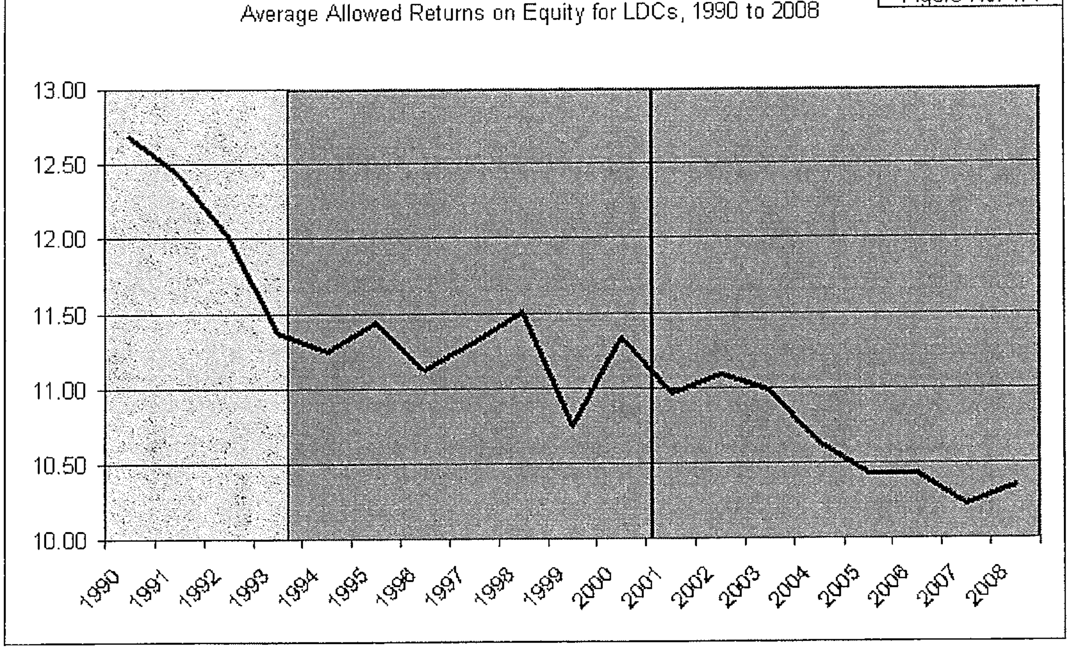
Then, in one additional observation, the common equity ratios to which these returns are applied have been observed over the same periods, comparing the equity ratios requested with those allowed, to determine trends in any gap between the two.

[1] Source: Regulatory Research Associates, SNL Financial, "Natural Gas, Past Rate Cases," July 2008—Data covers only the first half of 2008.

1. The Overall Average Allowed Returns, 1990 through 2007

As noted, Figure 1A measures the annual averaged RoE awards across all of the 377 rate cases decided on the merits during the 1990–2008 period.[2]

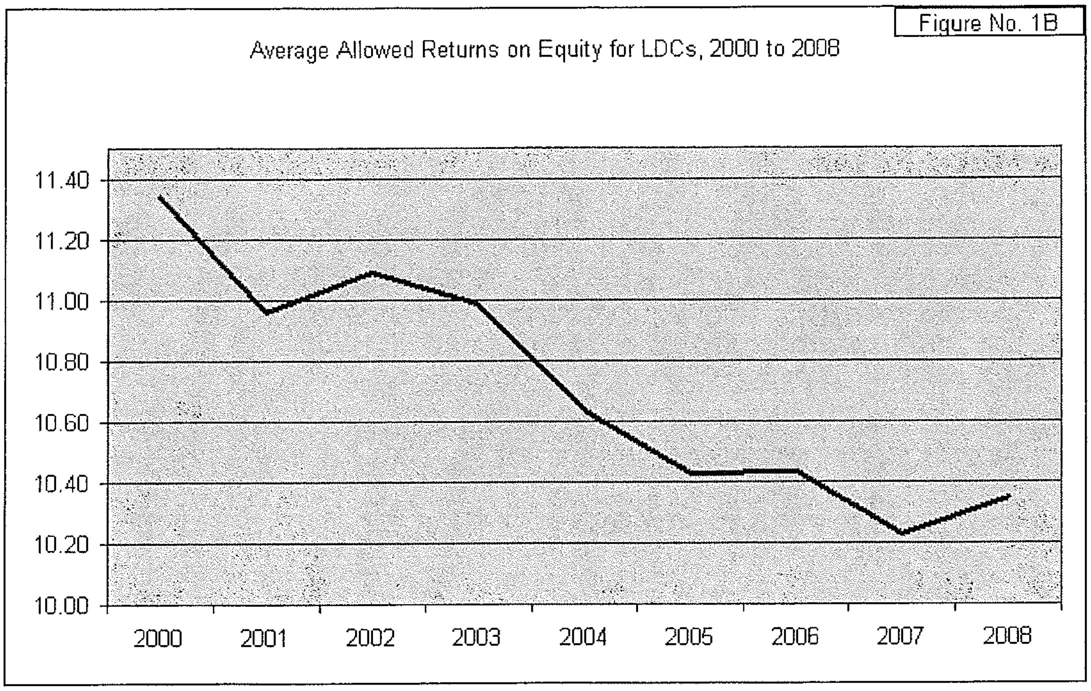
Figure No. 1A



From average levels in the 12.5 to 13 range at the beginning of the last decade, allowed returns declined into a relatively stable range between 11.0 and 11.5, from 1993 through 2000. Then a steady decline began, which has resulted in today's observed levels approaching 10 percent. In fact, there have been various recent awards below 10 percent, as will be discussed below.

[2] Ibid, extracted and analyzed by NCI.

The steady decline that supplanted the relative stability of the 1993–2000 period may be seen clearly with an amplified, focused observation of the 2000–2008 period, as set forth below in Figure No. 1B[3]:

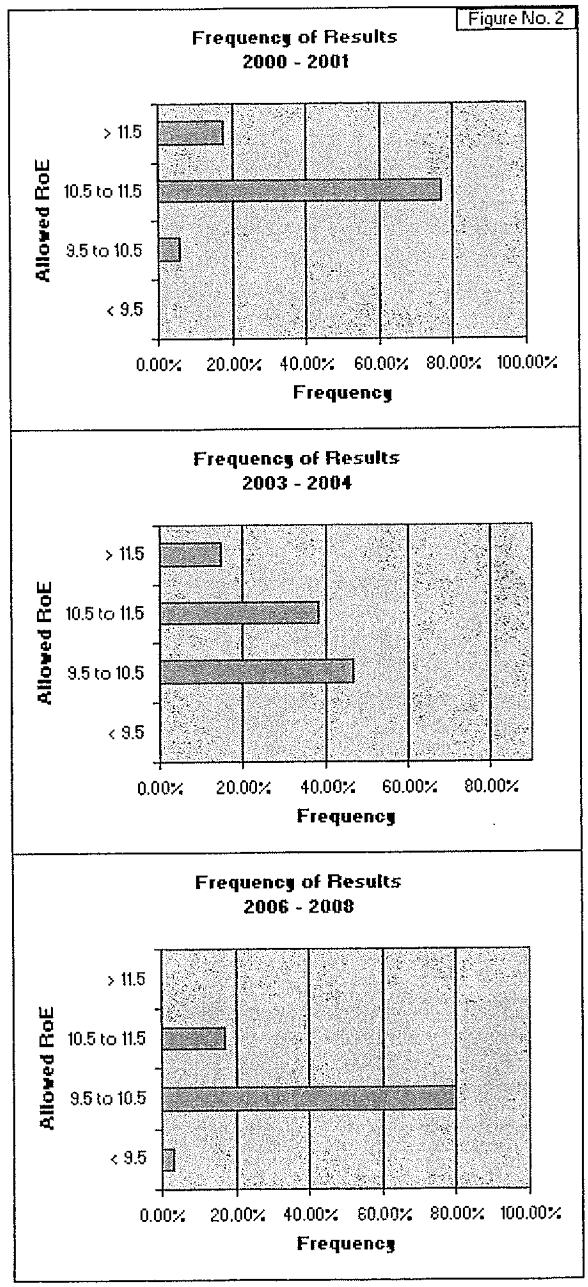


In part, the LDC industry has experienced a phenomenon similar to that experienced by interstate natural gas pipelines: Years of stable allowed returns within a fairly predictable band, followed by sudden exposure to returns significantly lower than those observed and expected at the time large past investments were made. Whether and how this could pose a significant challenge to new investment is explored in this study, primarily through the insights gained from the interview process. It is noteworthy and encouraging that there has been a slight uptick in the first half of 2008, with allowed returns averaging approximately 10.35 percent, but still well below historic levels.

[3] Same data as Figure No. 1A, stripped down to the 2000 – 2007 period only.

2. Distribution of the Allowed Returns

The pervasiveness of declines in allowed returns across the many jurisdictions studied is another factor that must be assessed – have the averages declined because of a few very low decisions, or has everyone's allowed return declined significantly? Figure No. 2 explores this question, examining the frequency of various ranges of allowed returns for three periods: 2000–2001, 2003–2004, and 2006–2008[4].



As Figure No. 2 shows, allowed returns in the first period, 2000–2001, were very tightly grouped in the 10.5 to 11.5 range – 76 percent of the allowed returns in those two years were within that range. A small group, about 18 percent, were higher, at levels above 11.5, and a much smaller group, about 6 percent, were in the 9.5 to 10.5 range. None fell below 9.5.

In the intermediate period, 2003–2004, we begin to see the decline, with the concentration moving down – to lower returns. The high (over 11.5) returns still constitute a measurable percentage, almost 15 percent of the total. However, the 10.5 to 11.5 category that dominated in 2000–2001 has dropped to 38 percent, and the lower 9.5 to 10.5 category has grown to 47 percent of total decisions.

The concentration toward significantly lower returns becomes fully apparent in the latest period, 2006–2008. Here, 80 percent of the allowed

[4] All data are from the same source and analysis as Figure Nos. 1A and 1B—Regulatory Research Associates, SNL Financial, "Natural Gas, Past Rate Cases," July 2008.

returns are in the 9.5 to 10.5 range (with more than half of those – 43 out of the 80 percent – being at or below 10 percent). We also see the emergence for the first time of a small percentage (one decision so far) below 9.5 percent.

Thus, there is no question that the decline in overall averages shown in Figure Nos. 1A and 1B is truly indicative of what is happening in most jurisdictions around the country. And, at a population of 377 rate case decisions, these are not anomalies.

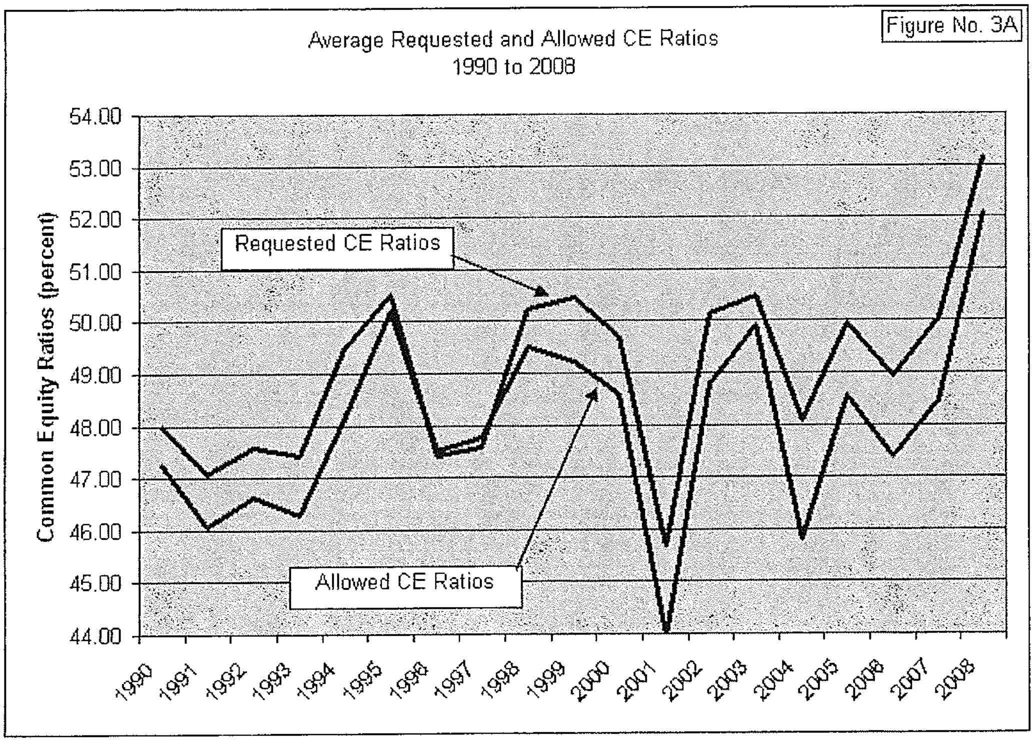
The fact of a decline in allowed returns on equity is merely that – a factual observation. The interpretation of such a decline – whether it is supportable, whether it is genuinely problematic for the industry or for public policy objectives, will depend on the actions of investors. Will they continue to invest in gas LDCs with these low returns or will they invest their capital in other businesses with similar risk that offer higher returns? An early indication of the answer to this question can be seen in the perceptions of the financial analysts and industry leaders who follow the industry.

3. Requested and Allowed Common Equity Ratios

Over the same 1990–2008 and 2000–2008 periods, the relationship between requested common equity ratios and the approved levels were examined. The common equity ratio is one of the most significant non-RoE rate elements in a rate case, in that a dollar of rate base that is deemed to be supported by debt, rather than by common equity, loses approximately 65 percent of its pre-tax earning power.[5]

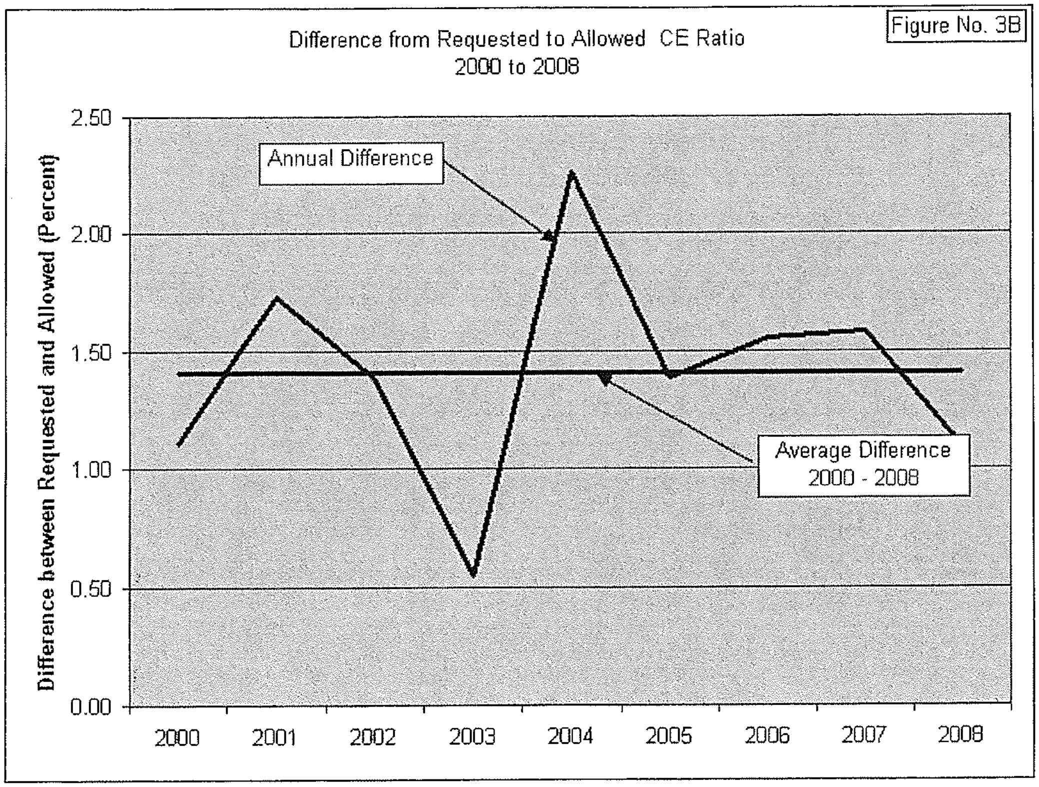
[5]Based on assumptions of an 11 percent RoE and a 6 percent interest rate, the pre-tax cost of a dollar of equity is approximately 17 percent, or 11 percentage points higher than the interest rate—thus according it only the debt cost rate under-prices the dollar of equity by 11 percent out of 17 percent, or 65 percent of its cost.

Figure No. 3A sets forth the average annual requested and allowed common equity ratios for the 348 LDC rate cases decided from 1990 through 2007 where a common equity ratio was stated. As with RoE, there were another 200 or so resolved rate cases wherein settlements did not state a number.



It is apparent from the plot that, beginning in the late 1990s, a broadening gap began emerging between the common-equity ratios represented by the LDCs themselves and those approved by regulators.

Figure No. 3B focuses on the 2000–2007 period, depicting the difference between requested and allowed common-equity ratios.



The annual decrement of allowed common–equity ratios below those requested by the LDCs has ranged between approximately 0.5 percent and slightly over 2.0 percent. The average for the eight-year period, represented by the red line, has been 1.41 percent.

This means that, on average, 1.41 percent of LDC rate base has been determined by regulators to be supported by lower-cost debt when the LDCs' own analyses indicated that it was supported by higher-cost common equity. Using a nationwide composite rate-base value for LDCs from the middle of the observation period,[6] this 1.41 percent difference would represent slightly more than $2 billion of investment that is "downgraded" from equity to debt.

When this happens, the LDC is left with a difficult choice: Allow equity investors to be chronically undercompensated, earning even less than the regulator's allowed return on equity, or refinance to higher leverage, thus incurring significantly higher financial risk. The end result of either course of action will be to disincent equity investment in the LDC.

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[6] Per AGA Gas Facts, the 2004 net investment (plant minus accrued depreciation, plus other investments such as storage) was $168 billion for the entire US LDC industry. The total accumulated deferred income-tax balance was $24 billion, resulting in a net rate-base value of $144 billion. The 1.41 percent of rate base deemed to be debt rather than equity is thus worth $2.1 billion (1.41 percent of $144 billion).

B. Perceptions of the Industry – Implications for Utility Sector

As noted earlier, extensive interviews were conducted in 2007-2008 with equity analysts, bond rating agencies, and senior gas industry executives. The executives interviewed ranged from the chief executive officers of utility holding companies wherein the LDC business is one component, to the chief executive officers of LDC business units within holding companies, to chief executive officers of pure stand-alone LDC businesses. The geographic distribution of the selected executives spanned the lower–48 United States, from east to west and north to south. In the case of both the financial community representatives and industry executives interviewed, there is no further identification or attribution in this report, in order to avoid singling out any particular company or jurisdiction. The purpose of the interviews is to gain a sense of the industry's perception, and to gain the benefit of any insights that might have application beyond specific individual jurisdictions. Accordingly, the results of the interviews are presented within the context of thematic discussion of issues, rather than as the results of a poll.

The results are grouped around seven themes:

Theme 1 – Are allowed returns threatening capital availability?
Theme 2 – If returns are inadequate, why are you still investing?
Theme 3 – If capital gets tight, what are the consequences?
Theme 4 – How do investors view the importance of allowed RoE?
Theme 5 – How does RoE interact with other regulatory issues, such as decoupling, pass-through trackers, etc.?
Theme 6 – What is the state of LDC riskiness today, and is that level of risk reflected in allowed RoE?
Theme 7 – What sort of best practices were observed in the interaction of PUCs with the regulated LDCs?

Theme 1 – Are Allowed Returns Threatening Capital Availability?

External Competition: Certainly, favorable tax treatment of dividends has helped support utility stocks in general (although there appears to be evolving market concern over the potential for expiration of that treatment). However, concern over reductions in the allowed rate of return is beginning to show up in analyst opinions. Some of these expressions of concern see low returns as symptomatic of a broader unfavorable regulatory environment in the particular states involved, and some of the expressions of concern simply have to do with the absolute level of allowed return. One equity analyst opined that allowed returns below 10.0 percent "send up a red flag" that the LDC business may not be a good investment going forward. Additionally, analysts note that the investor population has changed substantially in recent years, with the growth of hedge funds, private equity firms, etc. These entities respond much more quickly to negative indications than did the institutional investors in the past. Thus, an overall perception that allowed returns are inadequate could, in the view of some analysts, cause a very rapid exodus of capital from the LDC industry.

Debt-rating analysts are somewhat less concerned, depending upon the quality of regulation in a jurisdiction. From a debt perspective, the return on equity constitutes the "cushion" of cash, the coverage ratio that protects debt from fluctuations in the business. Thus, debt-rating analysts weigh the overall stability of revenues in the totality of the ratemaking system against the security they would require from the return on equity. Like equity analysts, they see low allowed returns as potentially symptomatic of overall negative regulatory environments, which would concern them greatly. However, if they are satisfied that the rest of the ratemaking process is in fact fair and conducive to stability, the debt-rating analysts are less concerned over allowed return on equity.

One major concern raised by debt-rating analysts over low allowed returns is the impact it has on the rated company's incentives. Low allowed returns strongly incent a company to shift investment from the LDC business to higher-growth, higher-risk lines of business, in the words of one major bond-rating analyst, which then can increase the overall financial volatility of the whole company. Such increased volatility is of great concern to the debt analysts, and can rapidly lead to downgrades that then increase the cost and decrease the availability of debt.

Internal Competition: Within multi-business holding companies, it was indicated that discretionary investments in the LDC business must compete with investments in pipelines, in unregulated businesses, etc., all of which exhibit significantly higher returns than those being allowed in the regulatory process in most jurisdictions. A specific exception is California, where generically derived RoEs above 11 percent have kept LDC subsidiaries on a level playing field with the risk-adjusted returns from other business lines. In general it was indicated that allowed returns had to be above the 10.5 range to avoid causing major concern, and that it required returns above 11 percent for going–forward discretionary capital programs to be relatively secure. When allowed returns are observed or expected to drift below 10.0 percent, all of the senior executives expressed deep concern over the availability of internally competitive capital. Additionally, it was noted by at least one company that at a 10.0 percent return on book equity, there is inadequate cash generated to pay dividends while retaining enough to grow at the rate expected by investors. This phenomenon will be discussed later in Sections IV and V.

An additional issue raised by multi-state LDCs was the competition for capital within the LDC sector, but between jurisdictions. In other words, if the LDC serves two states and one of those states exhibits generally lower returns than the other, the low-return state may lose the competition for discretionary investment.

A point that was emphasized is that the internal competition for capital within holding companies is not driven at all by the cost of debt – it is driven by the expected return on equity to be derived from alternative investments. Thus, a holding company with a marginal cost of debt of 6 percent that is choosing between an LDC investment and a pipeline investment at 12.5 percent will require the LDC investment to match a risk-adjusted version of the pipeline investment, rather than some risk-premium-adjusted version of the cost of debt. Accordingly, it is the alternative equity investment, the 12.5 percent pipeline investment, which determines what the LDC must earn to be competitive. Based upon historic experience, this LDC equivalent investment would need to earn 11.25 percent or greater to meet that criterion.

An important point regarding the internal competition for capital was that most executives saw it not for the potential to deprive them of capital for needed projects–their companies will continue to invest as needed to maintain the health of their systems. Rather, they saw it as the front-line indicator, the "canary in the coal mine," indicating looming problems in external capital markets.

Today's current credit and financial turmoil clearly adds to the concern raised by the financial community. The rapidly evolving difficulties in raising all types of capital, both debt and equity, would suggest that any negatively perceived factor, such as inadequate or declining allowed rates of return, could exacerbate an already problematic situation in funding new infrastructure.

The overall summary of the analysts' and companies' assessments of the decline in allowed returns is that significant pressure is already being experienced in internally competitive investment choices, and that capital flight in public markets is a real possibility given changes in the investor population. Impacts are primarily seen in discretionary investment, in that the vast bulk of dollars invested by LDCs are required by the obligation to serve or by safety/integrity rules. As more than one senior executive put it, "As long as we are in this business, we will invest what it takes to run the business safely and reliably. However, we will not invest beyond what is necessary to do so, and we will increasingly look for ways to get out of the business if the observed declines in allowed returns are expected to continue."

Theme 2 – If Returns Are Inadequate, Why Are You Still Investing?

In spite of the deep level of concern expressed by the bulk of the senior executives, it is clear that each of them continues to compete for both internal and external funds, and that substantial discretionary investments are being promoted, sometimes successfully. This led to one of the most frequently asked questions in response to concern over low allowed rates of return: Why are infrastructure replacement projects, market growth projects, and LDC acquisitions still taking place, if the returns are inadequate? The answers from the senior executives were all grounded in a combination of the prevention of loss of opportunities and in a fundamental trust for the regulatory and legal process over time.

Effectively, the consistent answer was this: If an opportunity presents itself to extend into a new market, to enhance the long-term health of the system by replacing infrastructure, or to expand by acquiring another company, that opportunity has two characteristics: its availability is time-sensitive, and its impact is long-term, usually spanning multiple decades. If the opportunity is passed up because of what should be a short-term deficiency in allowed rates of return, the opportunity may be gone forever.

The corollary observation made by several of the senior executives, and by at least one equity analyst, is that low allowed returns today are being applied to investment made in past years, based upon the same level of trust in the system. Accordingly, the current steady decline in allowed returns runs the risk of undermining that trust, and threatens the credibility of the executives who promoted the past, now-embedded investment. It was made very clear that if there is not evidence of a reversal of the downward trend–that is, if the implicit belief that the regulatory and legal processes will bring allowed returns back to the more stable, higher levels that pertained in the 1993 to 2000 period, there is some point at which the combination of trust in the system and reluctance to let opportunities pass by will no longer sustain investment momentum. If that happens, the senior executives emphasized that the resulting frustration of new investment will take a long time to reverse.

Theme 3 – If Capital Gets Tight, What Are the Consequences?

As noted, the executives interviewed all committed that as long as they are in the LDC business, they will invest what is necessary to run their systems safely and reliably. Thus the question is raised as to what happens, what suffers, if low allowed returns cause LDCs to be unable to attract capital. The first victim is discretionary investment, projects such as infrastructure replacement that can have long-term operating benefits to customers, but that are not absolutely required for current system operation. Discretionary investment can also include extensions outside of a current franchise area to bring service to new customers not subject to the obligation to serve. It can include operational enhancements such as storage, technological innovation, etc., that can add long-term efficiencies to a system, but that are not necessarily required. While the senior executives running LDCs continue to promote and fight for this kind of investment, the interviews yielded multiple anecdotes wherein the investment was not forthcoming.

While the primary bases for a fair rate of return are the constitutional and statutory standards requiring fairness to investors, the important public-policy consequence of inadequate returns would be the frustration of productive investment. This frustration and its impact on consumers are much harder to demonstrate for LDCs than for pipelines, primarily because LDCs are required to make such a large portion of their annual investment. However, from the sense of the interviews, the slowing of investment and the negative impact of that slowing are real.

One additional long-term impact on consumers of inadequate returns and a consequent reaction of investment markets was explained by the equity analysts. They described a scenario in which a combination of deteriorating debt coverage and perception by rating agencies that low returns demonstrate a negative regulatory environment ultimately lead to a downgrading of LDC debt. Characteristically, such downgrades take an extended period of time to reverse. So even if allowed returns are restored to healthier levels in response to a downgrade, the consumer cost of higher interest rates and of reduced limits on leverage could continue for years. The bottom line of this discussion was that the best answer for regulatory agencies is to "get it right in the first place."

Theme 4 – How Do Investors View the Importance of Allowed RoE?

The investment community's perspective on allowed RoE was best represented by the analysts interviewed. As noted, they spanned both equity analysts and bond–rating analysts. All felt fairly strongly that allowed returns are drifting down to levels that cause some alarm, but the extent of that alarm varied depending on the analyst.

In essence, the least alarmed of the analysts felt that, if a low RoE is part of a holistic package of rate and regulatory features crafted in an atmosphere of cooperation and trust between the LDC and the regulator, such a package can work. For example, the use of stabilization mechanisms such as decoupling, in concert with various types of incentive ratemaking can – again if and only if they have been the collaborative product of both the LDC and the regulator – go a long way to offset the impact of low rates of return.

However, the concern raised even by the least alarmed of the analysts is that low returns might become established when such a cooperative environment exists, then subsequent regulatory action begins to chip away at the stabilization and incentive mechanisms that balanced the low return. Additionally, as was pointed out not only by analysts but by company executives, it only takes a single major disallowance to cause major long-term financial damage to an LDC.

Beyond the holistic view expressed above, analysts are concerned that a combination of allowed RoE below 10 percent, with a demonstrated continuous downward slide for the last eight years, will cause broad disenchantment with LDC investment that could take years to reverse. The observation, expressed earlier, that shifts in the population of investors toward hedge funds and private equity make large, sudden shifts away from an industry easier and more likely than in the past was considered important by the analysts.

Uniformly, both equity and debt analysts considered the allowed RoE to be an important barometer of the regulatory treatment of the LDC. The steady decline demonstrated earlier is thus a matter of major concern. Additionally, of course, there is concern over the absolute level of the allowed returns, as compared with comparable investments of equal risk, either internally or externally. As allowed returns have drifted to and below 10 percent, the perception is that many investments of equivalent risk could earn more.

Theme 5 – How Does RoE Interact with Other Regulatory Issues, Such As Decoupling, Pass-through Trackers, etc.?

As is discussed in Theme 4, a broad, balanced package of rate and regulatory mechanisms including such stabilizing features as decoupling and some "upside" potential through mechanisms such as incentive rates can – if constructed collaboratively between the LDC and the regulator in an atmosphere of trust – offset some deficiencies in allowed return. It was emphasized by some analysts and executives that the development of this collaborative approach leads to the healthiest long-term regulatory environment.

However, beyond the role of such other issues as part of a balanced package, there is a strong tendency by regulators to accord great weight to the "de-risking" impact of mechanisms such as decoupling, resulting in decrements in the allowed rate or return. However, where RoE is set by reference to a proxy group of other LDCs, it is important to ask whether the observed results from those LDCs already reflect the impact of the same mechanisms. That is, if a population of proxy LDCs demonstrates an investor-required RoE of, say 11 percent, and if all of those proxy LDCs already have decoupling mechanism in place, it is inappropriate to apply an additional decrement to the indicated return to reflect the introduction of a decoupling mechanism in the LDC whose rates are being set. Among those in the industry, this kind of return decrement in response to mechanisms that stabilize rates for both the LDC and its customers was a matter of concern. All of them believe that such decrements are ill-advised and unfair.

Theme 6 – What is the State of LDC Riskiness Today, and Is that Level of Risk Reflected in Allowed RoE?

LDC executives expressed significant concern over regulatory perceptions that their business is not particularly risky. In particular, statements made by the FERC in its Kern River decision[7] to the effect that pipelines are more risky than LDCs drew a number of negative comments. However, at least when the pipeline-LDC comparison was explored more fully, it became clear that the LDC

[7] *Kern River Gas Transmission Company*, Opinion No. 486, 117FERC61,077 (2006).

executives were not demanding that they be considered fully as risky as pipelines, but rather that differences in allowed return between the two types of businesses should be maintained at no more than their historic levels. That is, whereas interstate pipeline rates of return have remained solidly in the 12 to 14 percent range for 30 years, LDC allowed rates of return have, at least in the decade prior to the current decline, stayed in a range from 10.75 to 12.5 percent. This would imply a fairly sustainable difference in allowed return between pipelines and LDCs of approximately 125 basis points.[8] The concern is that now, in a period when pipelines are expected to be at least at the lower end of the historically observed range of allowed returns (12 percent), LDC returns are experiencing a decrement from that level of at least 200 basis points, and in some cases 250 to 300 basis points. If pipelines prevail in their arguments at the FERC to move somewhat higher, say to 12.5 percent, the historic LDC decrement would suggest a prevailing LDC allowed return of 11.25 percent. In the view of the LDC executives, no rationale has been put forward to justify the much larger decrements being experienced.

Effect of Rate-Design Changes: As noted earlier, many regulatory authorities point to rate-design changes such as decoupling, weather normalization, etc., as having the effect of stabilizing the LDC's revenues and thus tempering volumetric risk. There is fairly broad acknowledgment among the LDC executives that, where such mechanisms are in place and are properly designed, they do have such an effect of stabilizing revenues and of stabilizing consumer costs. Of course, they point out, stability is a two-sided coin – protection against the down-side of load loss is offset by the loss of the upside of load gain. Thus, it is not as if the LDC has been unilaterally relieved of a risk, rather it has given up an upside gain opportunity for some protection against a downside risk.

It is also very important that mechanisms such as decoupling or revenue normalization be properly designed. For example, an adjustment mechanism to make up for load loss may, as is done in some jurisdictions, merely attempt to raise rates in only the same class of customer where the load was lost. Thus, for example, the impact of a lost industrial customer might be turned into a rate increase for the remaining industrial customers, but not for any of the other customers of the LDC. When that happens, the effect can easily be a death-spiral of the particular sector of load, the new rate increase driving off more industrial load, resulting in a further rate increase and so on. Thus, before the risk impact of any such revenue stabilization mechanism is built into a rate of return deliberation, the full impact of the mechanism must be understood.

A particular concern voiced by several executives was the tendency of regulators to apply a decrement either explicitly or implicitly to the allowed RoE as the trade-off for a decoupling mechanism. While the regulators justify doing so by

[8] This basis-point difference is consistent with FERC's finding in Kern River, where a 50-basis point difference was applied because the two out of four proxies had some significant share of LDC business, along with pipelines and production.

the allegation that the LDC's risks have been reduced, the executives point out that such a decision is often "double-counting." Because LDC RoE is usually set by reference to the financial results of other, similar utilities, if those utilities themselves have revenue-stabilization mechanisms in place, the impact of those mechanisms is already subsumed in the basic data being used to set RoE. Thus, the executives say, any additional decrement is unjustified and unfair.

Evolving and Increasing Business Risks: Meanwhile, regardless of the impact of such mechanisms, LDCs are exposed to a variety of risks that have been steadily increasing. These risks include unfunded government mandates, precipitous run-up in the cost of critical materials such as steel and in the cost of contract labor, the regulatory risk of cost disallowance, especially in periods of rapid gas-cost increase, and asymmetric regulation of uncollected gas cost (e.g., paying interest on overcollections but collecting no interest on undercollections). Additionally, in the competitive, unbundled world of today's interstate pipelines, the risk of bypass for LDCs' highest-volume customers – industrial and power generation – is pervasive.

It is important to contrast the impact of these evolving risks with the impact of the revenue volatility that is addressed by rate-design changes such as decoupling. As noted above, revenue stabilization is a two-sided coin: Before it took place, volatility caused by factors such as weather could and did result in increased earnings from time to time, in addition to the periods when it led to deficient earnings. Conversely, the evolving areas of increased risk are "one-way." They work only to the detriment of the LDC without the potential for a compensating upside. These areas of evolving risk are discussed individually:

- **Unfunded Government Mandates**

  Both the Federal and state governments place multiple, expensive requirements on LDCs that must be paid for not by funds provided by those governments, but by either ratepayers or investors. The most recent large-ticket examples of these requirements surround inspection and integrity evaluation. For example, under the Pipeline Safety Improvement Act of 2002 as enhanced by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, large scale and expensive inspections of transmission lines must be conducted, much more often than they were in the past. While much of the focus surrounding these statutes and the U.S. Department of Transportation regulations to implement them was on high-pressure interstate pipelines, there was actually an equal or larger estimated cost impact on LDCs. This is because LDC transmission lines – although far fewer and smaller than interstate transmission lines – are generally in "high-consequence" populated areas, thus triggering the most rigorous and costly requirements. The final DOT rule for distribution integrity management expected in 2009 would extend Federal inspection and integrity requirements to distribution systems themselves, at a cost estimated to be in the billions of dollars over the next several years.

As noted, every LDC executive interviewed reiterated the commitment to invest and spend the money necessary to ensure safety and reliability. On aging distribution systems, many of the costs required by Federal legislation may have been necessary anyway. However, the concern with uniform federally imposed mandates is that it can double the cost – performing the work required by Federal rules may not supplant the cost of inspections and replacements that would have gone on in the normal course of business.

The problem created by such unfunded mandates to incur operating expense and make substantial capital investment in inspections and replacements beyond what would normally be done is that they create costs that do not have any revenue-generation capability without a rate increase to customers. That is, investment in facilities that increase efficiency or add customers creates offsetting revenue that may preclude the need for a rate increase. However, required integrity investments must be recovered through increased rates, or will be absorbed by the LDC's investors.

None of the discussion questioned the advisability of uniform safety standards, but it was emphasized frequently that the full economic risk created by compliance falls on the LDC.

- **Increases in Construction Cost**

The LDC industry nationwide has consistently invested between $4 billion and $5 billion annually, for the last decade. Much of this investment has been required for system integrity, to meet regulatory mandates, and otherwise simply to maintain safe, reliable distribution networks. Much of the investment has also, of course, been made for purposes of providing new gas service to consumers. The cost of the inputs for all of this investment has risen dramatically in recent years.

According to anecdotal data provided by LDCs, individual components of LDC feeder line construction costs have increase 45–74% from 2002 to 2007:

- 4"-8" valves – 45%
- Steel fittings – 85%
- 2"-4" steel pipe – 4%
- 6"-12" steel pipe – 174%

In addition, contractor costs have risen dramatically, as demand for skilled services surged over the same period. Of course, regardless of construction cost, an LDC is theoretically allowed to include prudent investment in rate base. However, when costs increase at this pace, rate formulation can rarely keep up with them, even with a forward-looking test year. Additionally, to the extent that reduced allowed returns tend to place downward pressure on the LDC's ability to raise capital, radically increased size of those capital demands because of construction cost increases exacerbates the problem and thus becomes an ongoing risk increase for the LDC.

- **Gas-Cost Volatility**

Over the last few years, the wholesale market price for natural gas has experienced degrees of volatility never before seen. For example, during the last two winters, the spot price of gas at New York City has exceeded $30 per Dth, sometimes moving by double-digit amounts within one day. The primary industry benchmark wholesale price, Henry Hub, has generally been in a $7.00 to $8.00 range for some time, with significant daily and monthly volatility.

The impact of this volatility on LDCs has various aspects. Although virtually all LDCs do have a gas-cost tracking mechanism in their rates, the volatility of prices makes the forecast cost extremely difficult to predict. Thus, deviations between actual costs and forecast costs are frequent and large. If the deviation is an underrecovery, most LDCs are entitled to some manner of deferred recovery, but that recovery usually takes a full year and adds to the LDC's short-term financing requirements because in essence the unrecovered gas cost must be borrowed. If the deviation is an overrecovery, there is frequently a ratepayer backlash because of perceptions that the LDC was overcharging in past periods. Thus, volatility in gas prices has the dual effect of exposing large dollar amounts to extended recovery, financial cost and the attendant risk, combined with reaction and criticism among ratepayers and regulators when actuals deviate from forecasts, creating the risk of cost disallowance.

Most regulators view the LDC's ability to pass through gas costs as reducing risk. Certainly as compared with no such ability, such a reduction does occur. However, in RoE analyses that depend upon industry proxy groups, the risk-reducing effect of gas-cost tracking is a neutral factor, since all of the observed proxy companies have an equivalent ability. Meanwhile, it is important to recognize, as discussed above, that even a tracking mechanism cannot fully protect the LDC from the uncertainty and ratepayer backlash caused by large swings in gas cost.

- **Regulatory Disallowance**

  Of all the regulation-related risks, disallowance of costs is the most direct in its impact on the LDC's risk profile. Some costs such as contributions, economic development, dues and donations which are essential to the LDC's role as a member of its community, are routinely disallowed in some jurisdictions. This creates an automatic, chronic inability for the LDC to earn its allowed rate of return, despite the apparent business necessity of the expenses. The interviewees indicated that this sort of disallowance is never considered or compensated for in the model used to determine the allowed return.

  The larger risk, alluded to in discussing gas-cost volatility, is the unexpected disallowance of single major cost items, such as gas cost deemed to be excessive or the cost of treating certain supplies to meet quality specifications. The interviews cited at least one example of such a disallowance occurring in an amount equal to the LDC's full allowed return to investors for the year. That disallowance was ultimately reversed in court years later, but the financial market's perception of the risk remained. In general, PUC review of an LDC's gas cost and purchase policies is often after-the-fact, allowing attacks on past decisions with the benefit of hindsight. Accordingly, LDC sales service with its substantial gas-purchase obligation includes a good degree of risk in today's market.

- **Asymmetric Regulation of Uncollected Gas Cost**

  A factor affecting a number of LDCs, both in the risk/cost of gas-cost underrecoveries and in the pressure on their short-term financing capability is the treatment of the time value of deferred underrecoveries. Among LDCs recently surveyed as to the structure of their gas-cost,[9] it was learned that 62 percent either receive no interest on the recovery of unrecovered gas cost or they receive a lower time value of money than is paid on overrecoveries. This asymmetry adds to the financial risk entailed by gas-cost volatility and the probability of underrecoveries.

- **Risk of Bypass**

  LDCs have for years been faced with the potential to lose their largest individual customers, generally large industrial and power-generation loads. If such customers have access to the same interstate pipeline that serves the LDC, they frequently enjoy the economy of size to be able to justify connecting directly – eliminating the LDC as the middleman. This is especially true when the LDC's regulators have required a "tilt" in cost allocation and rate design in order to cause the large customers to

[9] This survey, conducted in 2005 for the American Gas Association, received responses from LDCs in 60 percent of the state jurisdictions, including all of the large, populous states.

subsidize smaller residential and commercial customers. According to the interviewees, market realities have largely forced regulators to phase out such subsidies – it has been recognized that maintaining the cross-subsidies runs the risk of losing the loads altogether.

For many LDCs, such large individual customers are still significant contributors to the LDC's total revenue profile. Yet, even if all rate cross-subsidies have been phased out of the charge to the large customer, it is still frequently cheaper to connect directly to a pipeline. Pipelines themselves are much more accessible and easily used by an industrial customer than was true in the past. FERC open-access, interconnection, capacity release, contract segmentation, and business-practice standardization have all served to make direct access to a pipeline much more feasible for an end-user than it was before those policies matured. In addition, many large marketers offer "asset management" services, whereby the end user can sign up for pipeline capacity, then hire the marketer to buy gas, manage the capacity, and make sure the correct quantities always reach the end user. Such marketers also manage large portfolios of capacity released by multiple shippers, sometimes including even the LDC's own pipeline contracts. These portfolios can allow them to serve the end user directly from the pipeline, without the end user ever being required to contract for pipeline capacity.

In short, bypass directly from pipelines to large end users has always been a risk for LDCs, but today the ease and feasibility of accomplishing that bypass are greater than ever. The impact of this risk varies widely across LDCs, depending on the degree of their reliance on large individual-customer loads.

Inability of New Business Margin to Sustain Growth: Another factor raised by some of the LDC executives, which goes partly to risk and partly to the inability of the LDC business to offset that risk, is the margin contribution from new business. When an LDC is compelled to add a new customer in its franchise area, the rules vary widely as to how the new customer's margin contribution will be set. In most jurisdictions, efforts have been made to avoid subsidization of the new customer by existing customers, so mechanisms such as capital contributions, limited-term surcharges, etc., have been used to ensure that the new customer fully covers its cost. However, this situation is at variance with many capital intensive businesses, where growth in demand actually gives a disproportionately large margin contribution. Basic capacity is put in place, and then marginal growth using that capacity has a low marginal growth and high marginal profitability. For LDCs who can barely cover the marginal cost of adding a new customer, growth does not offer this kind of contribution, which could make up for deficiencies in the earning capability of the embedded business. Thus, it is particularly important that the allowed rate of return on the embedded business be adequate.

Theme 7 – What Sort of Best Practices Were Observed in the Interaction of PUCs with the Regulated LDCs?

As noted in Theme 4, the financial community views with great favor those regulatory situations where the LDC and the regulator have worked together in an atmosphere of mutual trust, to craft balanced packages of rate and regulatory mechanisms. Such fairness and balance can offset some apparent deficiencies in allowed return since, first, such packages tend to stabilize revenues to reduce earnings volatility, and, second, where there is an atmosphere of mutual trust, the financial community can be confident that the regulator will work with the LDC to maintain financial integrity, regardless of the challenges faced – when there is a real problem, the LDC will be able to get timely relief. This is in sharp contrast to the more adversarial relationships that exist in some states, wherein the LDC faces a constant uphill struggle to achieve balance and stability in its regulated business. Thus, a definite "best practice" in both the regulator and the regulated is the development of collaborative initiatives that can foster an atmosphere of mutual trust. While this report does not generally single out specific jurisdictions, an exception is made here – according to analysts, New Jersey is an example of a state where such balance has been achieved.

Additionally, as noted in Theme 1, California has maintained mechanisms that periodically establish generic LDC returns in the state, using multiple analytical approaches to arrive at returns which the regulated LDCs have generally regarded as fair and adequate, at levels in excess of 11 percent. These were the sole LDCs interviewed that did not express concerns over capital constraints. Clearly some degree of trust and openness has evolved in the state to allow this to happen, and it is possible that other states could benefit by observing California.

IV. Reasons for Declines in Allowed RoE

There is no doubt that allowed returns on equity have steadily declined, as is measured and observed in Section III. Are the declines the result of changes in approach by regulators, or the result of the normal operation of the approved mechanisms, in the face of input numbers that have simply declined? For the most part, the reason appears to be the latter – simple evolution of the fundamental input data has been allowed to pull returns down through the mechanical operation of the favored regulatory tools for setting returns. A consistent theme sounded by industry executives in commenting on this evolution is the need for some sort of "human intervention," or benchmarking against actual investor expectations, to recalibrate the use of the approved mechanisms. This is often referred to as a "market-based reality check."

In particular, it is worth noting that the cost of debt built into rates is generally based upon an actual measurement of the debt instruments held by the subject utility, with the benefit of stated interest rates and other cost factors. In contrast, the cost of equity is always an estimate, based upon models that attempt to approximate investor requirements. Investors' actual requirements (the conceptual equivalent of an interest rate on a bond) are not directly measured. Accordingly, it would appear to be very important to find ways to ground RoE outcomes in something more than theoretical constructs that are merely assumed to mirror investor expectations.

There are three dominant mechanisms used to set allowed returns on equity in the regulatory arena: Discounted Cash Flow, Equity Risk Premium, and the Capital Asset Pricing Model. As a first step, each of the mechanisms will be explained, along with a brief description of the dynamics of the inputs to each. Then the interplay among the three mechanisms will be examined.

A. Discounted Cash Flow

Discounted Cash Flow, or DCF, is widely used throughout the state regulation of LDCs and is the exclusive method used at the FERC to set pipeline rates of return. DCF is an attempt to measure the expected cost of money for the typical investor in the stock of the regulated company. It does this by assuming that the market price of the stock is equal to the net present value of a perpetual future dividend stream, discounted to today's value at the investor's cost of money. This assumption is then turned into an equation to solve for the investor's cost of money in terms of the current stock price, the current dividend rate, and the expected rate of growth in earnings or enterprise value. Although the underlying math is fairly complex, the ultimate formula that results from the process is extremely simple:

$$\mathbf{K = D/P + g}$$

Where "K" is the investor's cost of money, "D" is the annual dividend, "P" is the stock price, and "g" is the rate of growth.

These factors are not generally directly available for an individual LDC, since most LDCs are subsidiaries of larger companies and thus are not publicly traded. So the normal practice is to use "proxy" companies, or a population of publicly traded companies with significant LDC business that are considered similar enough to the LDC in question to be used as benchmarks in determining what investors will expect out of the LDC in question.

Probably the best way to demonstrate the operation of the DCF formula by a PUC and to discuss its implicit issues is to use a real-world example. The example used here is taken from an actual LDC rate case in 2007, without naming the LDC or the jurisdiction. Similarly, the specific proxy companies used in the analysis have been designated simply as "LDC 1" through "LDC 12," to avoid any prejudice arising from their representation here. Based on the author's experience, this extract from a PUC staff witness's analysis (shown below in Figure No. 4) is quite typical of the application of DCF in the state regulatory arena throughout the United States.

DCF Example from PUC Staff Exhibits **Figure No. 4**

Company	13 week Avg. Price	Current Dividend	Dividend Yield	Average Growth 10_/	Cost of Equity
LDC 1	$42.75	1.64	3.84%	5.9%	9.8%
LDC 2	$31.80	1.28	4.03%	6.2%	10.2%
LDC 3	$31.47	1.46	4.64%	4.4%	9.1%
LDC 4	$52.69	1.52	2.88%	6.6%	9.5%
LDC 5	$48.89	1.86	3.80%	2.9%	6.8%
LDC 6	$48.45	1.42	2.93%	4.7%	7.7%
LDC 7	$26.59	1.00	3.76%	4.2%	8.0%
LDC 8	$38.47	0.98	2.55%	9.4%	12.0%
LDC 9	$31.73	0.40	1.26%	11.3%	12.6%
LDC 10	$38.24	0.86	2.25%	6.6%	8.9%
LDC 11	$27.76	0.70	2.52%	11.6%	14.2%
LDC 12	$33.65	1.37	4.07%	3.1%	7.2%

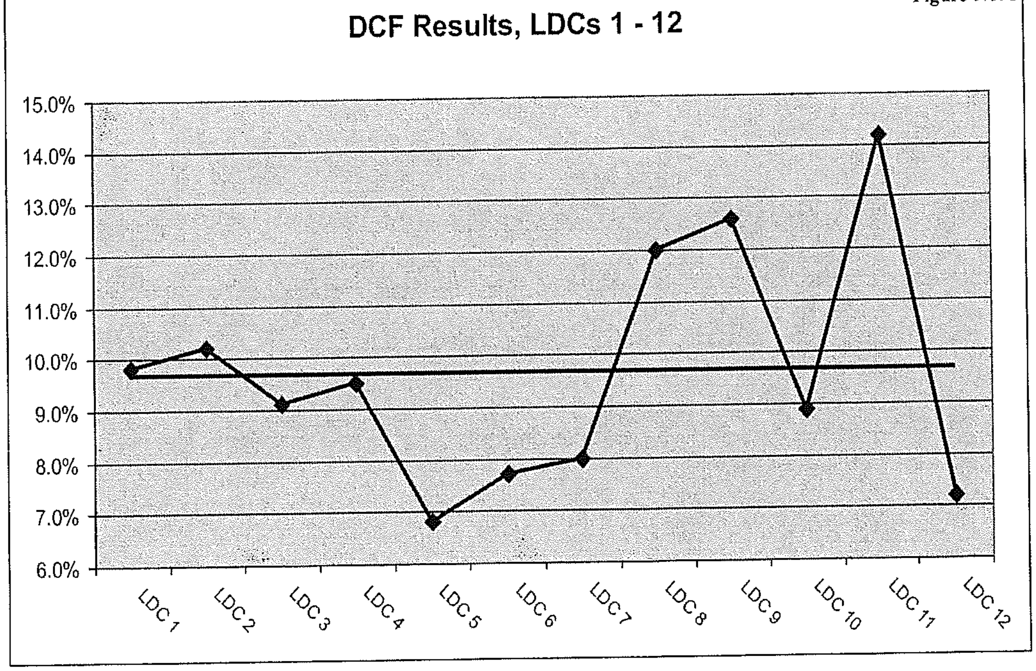
The DCF calculation described above is applied by first determining a dividend yield rate for each proxy (dividend divided by market price), then adding to that dividend yield rate the expected rate of growth in earnings and dividends. Then the resulting costs of equity for the proxy companies are used as a range within which the company at issue is placed, based on its relative risk. Typically, without compelling evidence to the contrary, a company is placed at the median, the midpoint, or the average of the range. In the range shown above, from a low of 6.8 percent to a high of 14.2 percent, the average would be 9.7 percent.

In other words, a typical PUC application of the DCF methodology using current market numbers yields the sort of below 10 percent result about which the industry interview subjects express such concern. Are there aspects of this calculation that argue for reexamination of the methodology? There are at least three observations that suggest something beyond this DCF calculation would be appropriate.

[10] The Growth rates used are averages of four different calculations, including historic and projected growth in earnings per share, historic and projected growth in book value per share, and growth in assumed retained earnings. The end result is intended to represent the rate of growth in earnings and dividends that investors could reasonably expect from each proxy company.

First, there is simply the very wide diversity of the results, for twelve companies that should ostensibly be quite similar. Graphically, as presented in Figure No. 5, this wide diversity is quite apparent:

Figure No. 5



From the lowest result to the highest result, there is a difference of 740 basis points. Interestingly, there is very little similarity between the "proxy" results shown for these twelve individual companies, and the actual allowed rates of return determined by their own PUCs. In short, there is a real question as to whether this genuinely defines the range of real investor expectations that can simply be averaged to yield a fair return. The potential for shortcomings in this analysis have been less apparent in the past when depressed stock prices gave high yield rates, and when various measures of growth pushed the numbers somewhat higher. However, today, arguing that a measured cost of money ranges from 6.8 percent to 14.2 percent, and that therefore an average of 9.7 percent is appropriate would appear to be a misuse of averages.

The second observation as to this DCF approach is its inherent circularity. As noted, the approach set forth in Figure No. 4 is very typical of PUC applications of the methodology, both in the calculation itself and in the selection of the proxies. If all the proxy companies are LDCs whose returns are set the same way, then measuring historical performance and Wall Street expectations of growth will always reflect the outcome of the same methodology that is being applied to measure that outcome. So if the DCF methodology is yielding an inadequate result, the inadequacy would affect most or all of the proxy companies as well. Thus, even if accurate, DCF would measure the cost of money necessary to compete for capital with other LDCs, but would not measure the ability of the whole industry to compete for capital with other businesses with similar risk not subject to this regulatory regime.

The last observation goes not to the theory or calculation of the DCF cost of money, but to the use to which it is put. By developing a cost of equity based upon stockholder expectations in the stock market, at best the methodology yields the individual investor's expectation of long-term return on a share of LDC stock. The next step, applying this number directly as a return on book equity, creates a potential disconnect – it is now limiting the specific cash return on rate base that will be available to achieve the investor's expectations. That cash be sufficient? To answer this question, we have to assess two factors: The LDC's ability to pay its current dividend and the LDC's ability to achieve the growth in earnings and net book that is required by investors. If we assume that the primary driver of growth in earnings per share or net book value per share is the growth in retained earnings, it is possible to test the DCF-derived return for adequacy.

Figure No. 6 first derives the average values for each of the building blocks and for overall return, for the proxy group from Figure No. 4. Then it adds one more piece of data, the average book value per share for the proxy group (which is 19.22 as of the time of the other data used in the analysis, for a market-to-book ratio of 2.0). In essence, we are building the hypothetical "average" LDC on which the return is based. A dividend yield of 3.3 percent is added to a growth rate of 6.4 percent, for a cost of equity of 9.7 percent.

Test for Growth Deficiency						Figure No. 6
Price	Dividend	Yield	Growth	Cost of Equity	Average Book	Market-Book
$37.71	$1.21	3.3%	6.4%	9.7%	19.22	2.0
EPS	Dividend	Remaining Earnings	Growth in Book	Marginal EPS	Growth in EPS	Growth Deficiency
$1.86	$1.21	$0.65	3.5%	$0.063	3.4%	-3.0%

But then we come to the second line of Figure No. 6. What happens when the 9.7 percent return is applied to book rate base? The book value of equity rate base is only $19.22 per share, as opposed to a market stock price of $37.71. Thus, 9.7 percent times rate base will generate earnings of $1.86 per share. Those earnings must first pay the current dividend of $1.21, leaving 65¢ per share to fuel growth. How much growth will it fuel? The 65¢ represents a 3.5 percent growth in the net book value of $19.22. As a rate of growth in earnings per share, we would multiply the 9.7 percent rate of return times that 65¢ of new equity, generating 6.3 cents of new earnings, or a rate of growth in earnings per share of 3.4 percent. According to the original study, however, investors require a rate of growth of 6.4 percent–there is an apparent growth deficiency of 3.0 percent, between the required rate and the average of the actual book and earnings growth rates. This could be problematic – the effect over time would be for the LDC to miss investor expectations by a significant amount, causing declines in the stock price. The natural reaction of the LDC's owners – indeed, their fiduciary responsibility to their investors – would be to invest in other activities that would make up the deficiency. Investment would flow away from the LDC.

Many of the issues raised over the use of DCF in setting returns have to do with the original purpose of DCF analysis – and the way it is still used by major investment analysts. That original purpose was and is for the comparison of alternative investments, rather than to derive an absolute level of investor-required return. For example, DCF is quite useful for distinguishing the twelve proxy companies from each other, regardless of the absolute level of return that might be appropriate. Its accuracy as to such absolute levels has been assumed more than demonstrated. It is this tension that underlies many of the concerns over the intersection between DCF financial theory and application of that theory in a cost-based regulatory arena.

Possible approaches for addressing the various observed concerns regarding DCF analysis are discussed in Section V – Potential Changes and Adjustments.

B. Equity Risk Premium and the Capital Asset Pricing Model

Equity Risk Premium (ERP) is an approach that simply assumes the cost of equity will track the interest rates for various types of debt. The realized returns in equity markets are compared over time with concurrent interest rates, to determine the premium that must be earned by stockholders in order to attract them from less risky debt to more risky equity. Sometimes the ERP is measured from "risk-free" debt, generally long-term government bonds; sometimes it is measured from various high-quality corporate bonds.

The Capital Asset Pricing Model (CAPM) is really just a further refinement of ERP. Whereas ERP determines a premium generally required of equity markets, CAPM translates it to the individual stock, using a measure of that stock's volatility vs. the stock market at large.

It is not necessary to produce representative studies to show the role of ERP and CAPM in the current decline in allowed returns. No one questions that interest rates have declined substantially over the past decade, so any method that holds a constant relationship between equity and debt costs will result in substantially reduced returns on equity.

Equity Risk Premium

ERP is more often used as a check than as a primary source of allowed returns. However, probably its more significant impact is that even when ERP is not technically the method being applied, it is clearly behind the regulatory psychology surrounding returns on equity, regardless of how they are derived. In times of deeply reduced interest rates, regulators and consumers expect utility allowed returns to be reduced equally substantially (although, unfortunately, this logic does not always fully work in the other direction, when interest rates are high).

There are two issues often raised as to this assumption. First, the relative size of an equity risk premium over debt cost has been the subject of much debate-especially as to how that premium behaves in different interest-rate regimes. The argument is made that the ERP expands during low-interest rate periods and contracts during high-interest-rate periods. As a practical matter, this was certainly the approach taken by regulators in the early 1980s, when the prime rate was in the high teens.

It is also the approach that has evolved over time in Canada, where since the mid-1990s returns on equity have been set by automatic formulae that track long-term bond interest rates. As those interest rates change, the allowed return on equity is adjusted by just 75 percent (the "elasticity factor") of the change, not by the full movement. This has the effect of shrinking the ERP when interest rates are high and expanding the ERP when interest rates are low. There is considerable debate in Canada over the size of the elasticity factor. Most of the industry and some prominent former regulators have suggested that the factor should have been lower-probably at approximately 50 percent. However, the concept is the same – an acceptance that market-required returns on equity do not track interest rates percent-for-percent.

The other issue, less empirical than the observed movement of the cost of equity as compared with interest rates, is the basic competition for capital in which the cost of equity is the measure of competitiveness. As the 2006 INGAA paper referenced earlier pointed out, and as was emphasized repeatedly by both senior executives and analysts in this AGF Study effort, the cost of equity is an opportunity cost issue, whether in the open market or in the capital-allocation process of a multi-business holding company. Essentially, if an investor's only alternative to investing in an LDC stock is to buy a bond, the required risk-premium to move the decision in favor of the LDC equity is important. However, a bond is generally not the only alternative investment – in the actual market, the investor can choose among multiple equities of which the LDC stock is one. In making this choice, the only important factor is what the investor's earnings would have been in those alternative equity investments. In other words, in the case of the stand-alone LDC the equity investor is free to move his or her capital to other businesses with that offer better returns without a significant increase in risk.

Similarly, if a holding company is solely making a choice between investing in its LDC subsidiary and issuing or retiring debt, the difference between the expected LDC earnings rate and the interest rate on the debt in question is relevant and important. However, if the holding company is allocating a fixed capital pool (consisting in part of borrowings based on achieving a particular corporate capital structure), the holding company is making choices among competing investments, requiring the LDC to meet the risk-adjusted return from the alternatives. If the holding company could earn 12.5 percent by investing in a pipeline and, in the holding company's judgment, the risk adjustment between the pipeline and the LDC is the historically observed 125 basis points, the LDC must earn 11.25 percent to compete – regardless of what the holding company's debt cost may be.

Capital Asset Pricing Model

As noted, CAPM is primarily a refinement of ERP, in that it adjusts the risk premium for the individual stock's observed relationship to the stock market as a whole. This relationship is defined by the stock's Beta, or volatility. Like DCF, CAPM is characterized by a great deal of background mathematical analysis (its original creators won the Nobel Prize for it), but a very simple ultimate formula:

$$\mathbf{K = Rf + \beta \ X \ ERP}$$

where "K" is the equity investor's cost of money, "Rf" is a risk-free interest rate (usually long-term Treasury bills), "β" is the individual stock's volatility vs. the overall stock market, and "ERP" is the equity risk premium for stocks generally.

The obvious issue with CAPM is that if "Beta" is less than 1.0, the company being examined will be assumed to need a lower than average risk premium. Many utilities exhibit Betas below 1.0.

Figure No. 7 sets forth the Betas for the twelve proxy companies examined in Section IV A.

Figure No. 7

Company	Beta
LDC 1	0.32
LDC 2	0.59
LDC 3	0.92
LDC 4	0.62
LDC 5	0.65
LDC 6	0.77
LDC 7	0.58
LDC 8	0.66
LDC 9	1.20
LDC 10	0.59
LDC 11	0.70
LDC 12	0.90

Of these twelve major LDC holding companies, only one has a Beta above one. There is also the same sort of extremely wide diversity observed in the DCF comparison, with Betas ranging from 0.32 to 1.20. This would mean that for an ERP of, for example, 7.1 percent, [11] the indicated returns for the proxy LDCs would vary by as much as 625 basis points.

Assuming a risk-free rate and a Market Risk Premium of 4.66 percent and 7.08 percent respectively,[12] the resulting returns are as shown in Figure No. 8. The average is coincidentally the same as the average of the DCF results, but the high is 100 basis points lower and the low is 200 basis points higher than the DCF results – and the individual companies vary quite widely, by as much as 460 basis points (LDC 11, at 9.60 percent here, but 14.20 percent per the DCF study).

Figure No. 8

Company	Beta	Cost of Equity
LDC 1	0.32	6.9%
LDC 2	0.59	8.8%
LDC 3	0.92	11.2%
LDC 4	0.62	9.0%
LDC 5	0.65	9.3%
LDC 6	0.77	10.1%
LDC 7	0.58	8.8%
LDC 8	0.66	9.3%
LDC 9	1.20	13.2%
LDC 10	0.59	8.8%
LDC 11	0.70	9.6%
LDC 12	0.90	11.0%
	Average	9.7%

As is discussed above with regard to ERP, CAPM follows a lock-step relationship with interest rates that does not reflect equity-to-equity competition based on opportunity cost. Thus, as with DCF, CAPM can be a useful tool for the comparison of similar investments, but may be of questionable use in deriving an absolute cost of capital.

[11] The widely accepted Ibbotson-Sinquefield average for 1928 through 2005 is 7.08 percent. Some other sources, such as Damodaran Online, quantify a lower MRP, at or below 5 percent.
[12] The MRP of 7.08 percent is per footnote 10, the 4.66 percent Rf is per Damodaran Online.

Obviously, if the growth objectives quantified in the DCF analysis are to be met, a 9.7 percent return derived by CAPM is just as deficient as a 9.7 percent return derived with DCF.

V. Potential Changes and Adjustments

As is noted earlier, adjustments could be made to each of the prevailing methodologies, or somewhat different approaches taken, to respond to perceived deficiencies. This section itemizes what those changes might be and the challenges in implementing such changes.

A. Broaden Proxy Groups

Along the same lines as the debate recently resolved involving pipeline proxy groups (see B. below), LDCs could look farther afield than their own industry for proxy companies. The standard to date for the selection of proxies has always started with the notion that the comparable companies must be regulated utilities, primarily in the gas business. However, this standard implicitly causes the circularity discussed in Section IV. Since the key distinguishing factor is risk, LDCs and regulators could be well served to identify unregulated infrastructure companies with risk levels analogous to those of the LDC. The measured market expectations for those unregulated companies would then be undiluted by the results of regulatory policy.

B. Use FERC Decisions as Reference Point, Maintain Historic Gap

There have been several references to the historic 125 basis point difference between pipeline returns and LDC returns. One option would be to maintain that difference. This approach has been uncertain to fix all deficiencies unless pipeline rates of return were maintained at their historic levels in the 12 to 14 percent range. The Kern River decision, cited earlier, resulted in a return on equity of 11.20 percent – application of the 125 basis-point difference to that number would fall below 10 percent, but the pipeline industry has been adamant that the Kern River decision was itself an inadequate rate of return.

The key issue in the pipeline industry has been the composition of proxy groups, with pipelines seeking the inclusion of pipelines organized as master limited partnerships (MLPs), in order to repopulate the proxy groups. On April 17, 2008, the FERC issued a statement of policy and a reopening of the Kern River case, allowing such inclusion of MLPs. The statement of policy requires some adjustment to the assumed long-term growth rate for the MLP members of the proxy group, but overall, it appears that the resulting rates of return will be restored to approximately the 12 percent level.[13] Thus, something on the order of

[13] FERC Docket No. PL07-2.

10.75 percent to 11.00 percent would be implied for LDCs, if the FERC level is maintained and the pipeline-LDC gap is maintained as well.

C. Variations on CAPM, Particularly Fama-French

The Fama-French methodology is a variant of CAPM that uses more than the broad, full-market average results for stocks to derive a risk premium. It includes some proportion of high-growth and small-cap stocks, thus generally resulting in significantly higher returns than unadjusted CAPM would have. Some LDCs, both in the U.S. and Canada, have tried to gain acceptance of Fama-French in their own proceedings, with mixed but very limited success.

D. Restore Growth Deficiency in DCF

The inherent deficiency of growth below that assumed to be necessary in the DCF formula should be a fertile ground to explore. Regulators can argue that growth can come from sources other than retained earnings. However, regulators appear generally to accept the notion that a buildup of retained earnings is necessary to sustain growth in either book value or earnings per share.

The adjustment to compensate for the deficiency is simple – in the example, where growth is 3.0 percent below expectations, the 3.0 percent is simply added to the indicated return, for a total of 12.7 percent (if full restoration of the growth deficiency is deemed appropriate). In the Figure No. 6 example in Section IV, using the 12.7 percent return on book equity would yield $2.43 of earnings, which, when netted for the $1.21 dividend, would leave $1.22 of retained earnings. Investing the $1.22 in the LDC business at a return of 12.7 percent would yield 15.5¢ of new earnings, which is 6.4 percent of the original $2.43 of base earnings. In other words, the $2.43 of earnings per share is growing at 6.4 percent, as it is supposed to. Net book, which started at $19.22 per share, grows by $1.22, which is also a 6.4 percent rate of growth.

How does this 12.7 percent indicated return reconcile with the earlier observations that something lower, perhaps 11.25 percent, should be adequate? The reconciliation could be based upon restoring only part of the growth deficiency, assuming that some factors other than retained earnings from return-times-rate base do contribute – 11.25 percent would represent restoring just over half of the growth deficiency.

The central rationale of the growth-deficiency restoration is that the application of a market-based DCF result to book rate base does not generate enough money to pay required dividends and generate the growth that the regulator itself has determined is expected by investors. However, there are counter arguments to making the adjustment – most notably the argument that rates are being set to sustain market share values above book. The tension between this concern and the concern that returns be set to put LDC investment on a level playing field deserve a full policy discussion with regulators.

E. Thresholds for Adjustments to Be Contemplated by Regulators

The mechanics of changes, whether they are changes in the proxy group, references to pipeline returns, or adoptions of new methodologies such as Fama-French or growth-deficiency restoration, all require a willingness and enthusiasm on the part of regulators that is not apparent in most jurisdictions. The challenge for the industry is to generate sufficient credibility and confidence in state commissions that a steady decline in allowed returns is causing a looming public-policy problem. Certainly, each LDC can go forward based on the statutory right to a fair return, but moving toward significant changes will probably take more proactive help from regulators than can be gained from winning a court case. Clearly, the lesson learned through the analysis process was that the jurisdictions with an atmosphere of trust and collaboration appear to be fostering the healthiest LDCs.

The bottom line in all instances is credibility. If credibility is generated within the state commission, more positive changes are likely to happen, although there is no guarantee the state commission will incur the political heat of increasing rates. If credibility is generated with legislators and courts, there is more likely acceptance of the types of analyses contained within this AGF Report. In some notable instances (one leading one being the FERC conference in 1998), it has been the face-to-face interaction of senior executives and analysts with regulators, in a public arena where critics are free to criticize, that has generated enough credibility to foster significant change in rates of return. Most LDCs already have such discussions at the state level, but the trend in allowed returns suggests that more are needed.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

25. Provide the most current Returns on Equity ("ROE") awarded by their respective regulatory agencies and the dates of the awards for the proxy group of utilities ("Gas Group"), or for their gas utility subsidiaries if the proxy company is a holding company.

Response:

Please refer to the attached spreadsheet.

Group of Gas Distribution Companies

Ticker	Company	Date	Authorized Return on Equity
GAS	AGL Resources, Inc.		
	Florida	2/9/2004	11.25%
	Georgia	11/3/2010	10.75%
	Illinois	3/25/2009	10.17%
	New Jersey	12/17/2009	10.30%
	Tennessee	5/24/2010	10.05%
	Virginia	12/20/2011	10.00%
ATO	Atmos Energy Corp.		
	Georgia	3/31/2010	10.70%
	Kansas	8/22/2012	NA
	Kentucky	5/28/2010	NA
	Louisiana	4/17/1996	10.77%
	Mississippi	11/8/1985	12.94%
	Tennessee	11/8/2012	10.10%
	Texas	12/4/2012	10.50%
LG	Laclede Group, Inc.		
	Missouri	3/13/2013	NA
NJR	New Jersey Resources Corp.		
	New Jersey	10/3/2008	10.30%
NWN	Northwest Natural Gas		
	Oregon	10/26/2012	9.50%
	Washington	12/26/2008	10.10%
PNY	Piedmont Natural Gas Co.		
	North Carolina	10/24/2008	10.60%
	South Carolina	11/1/2002	12.60%
	Tennessee	1/23/2012	10.20%
SJI	South Jersey Industries, Inc.		
	New Jersey	9/16/2010	10.30%
SWX	Southwest Gas Corporation		
	Arizona	12/13/2011	9.50%
	California	11/21/2008	10.50%
	Nevada	10/31/2012	10.00%
WGL	WGL Holdings, Inc.		
	District of Columbia	5/10/2013	9.25%
	Maryland	11/14/2011	9.60%
	Virginia	7/2/2012	9.75%

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

26. Provide the Value Line pages for the Gas Group used in the ROE analysis.

Response:

The requested Value Line pages are attached.

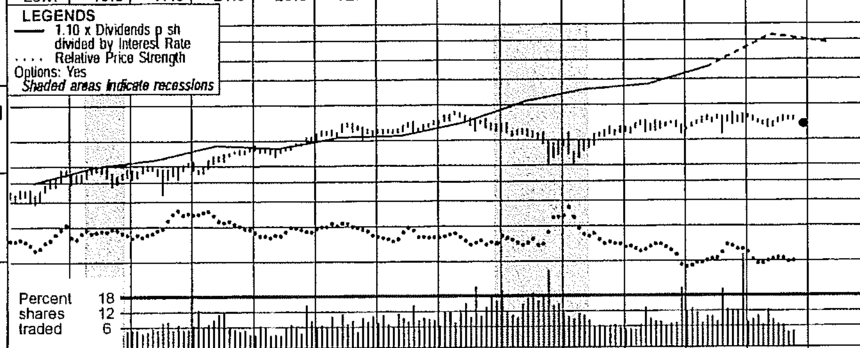
AGL RESOURCES NYSE-GAS

RECENT PRICE 38.41 | P/E RATIO 11.0 (Trailing: 20.3 / Median: 13.0) | RELATIVE P/E RATIO 0.74 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 3 Raised 3/11/11
SAFETY 1 Raised 9/9/11
TECHNICAL 3 Lowered 11/23/12
BETA .75 (1.00 = Market)

High:	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9				
Low:	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6				

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+70%)	18%
Low	50	(+30%)	11%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	0	0	2	0	0	2	0
to Sell	0	1	0	0	2	0	0	2	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	258	153	136
to Sell	63	159	151
Hld's(000)	71384	71603	69954

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.9	10.8
3 yr.	34.2	48.5
5 yr.	31.4	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	20.00	*34.95*	*37.15*	Revenues per sh A	*44.30*
2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.05	*6.00*	*6.15*	"Cash Flow" per sh	*7.35*
1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	*2.70*	*3.20*	Earnings per sh A B	*3.80*
1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	1.90	*1.74*	*1.84*	Div'ds Decl'd per sh CF■	*1.96*
2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.42	*4.75*	*5.15*	Cap'l Spending per sh	*6.45*
10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	28.54	*30.90*	*31.65*	Book Value per sh D	*33.30*
55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.00	*117.00*	*117.00*	Common Shs Outst'g E	*117.0*
13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	.82	*Value Line*		Relative P/E Ratio	*1.00*
5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*
						868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	*4100*	*4350*	Revenues ($mill) A	*5180*
						103.0	132.4	153.0	193.0	212.0	211.0	207.6	222.0	234.0	172.0	*315*	*375*	Net Profit ($mill)	*445*
						36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	*35.5%*	*32.0%*	Income Tax Rate	*32.0%*
						11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	*7.7%*	*8.6%*	Net Profit Margin	*8.6%*
						58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	52.0%	*52.0%*	*52.5%*	Long-Term Debt Ratio	*56.0%*
						41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	48.0%	*48.0%*	*47.5%*	Common Equity Ratio	*44.0%*
						1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	8238.0	*7535*	*7855*	Total Capital ($mill)	*8840*
						2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	*8375*	*8875*	Net Plant ($mill)	*10570*
						8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	3.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
						14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*9.0%*	*10.0%*	Return on Shr. Equity	*11.5%*
						14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*3.0%*	*4.5%*	Return on Com Equity	*5.5%*
						7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	.7%	*3.0%*	*4.0%*	Retained to Com Eq	*6.5%*
						52%	53%	49%	52%	52%	58%	60%	57%	57%	86%	*65%*	*58%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $4604 mill. **Due In 5 Yrs** $100 mill.
LT Debt $3330 mill. **LT Interest** $200 mill.
(Total interest coverage: 6.5x)

Leases, Uncapitalized Annual rentals $95.0 mill.
Pension Assets-12/11 $754.0 mill.
Oblig. $968.0 mill.

Pfd Stock None

Common Stock 117,782,207 shs.
as of 10/23/12

MARKET CAP: $4.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	24	69	91
Other	2138	2677	2044
Current Assets	2162	2746	2135
Accts Payable	184	294	292
Debt Due	1032	1338	1274
Other	1212	1452	1198
Current Liab.	2428	3984	2764
Fix. Chg. Cov.	501%	325%	385%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	5.5%	9.0%
"Cash Flow"	6.5%	6.0%	9.0%
Earnings	9.0%	4.5%	6.0%
Dividends	5.0%	7.5%	1.5%
Book Value	7.0%	5.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	995	377	307	638	2317
2010	1003	359	346	665	2373
2011	878	375	295	790	2338
2012	1404	686	614	*1396*	*4100*
2013	*1780*	*690*	*585*	*1295*	*4350*

Cal-endar	EARNINGS PER SHARE AB Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.55	.26	.16	.91	2.88
2010	1.73	.17	.29	.81	3.00
2011	1.59	.23	d.04	.37	2.12
2012	1.12	.28	.08	*1.22*	*2.70*
2013	*1.95*	*.25*	*.15*	*.85*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID CF■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.42	.42	.42	.42	1.68
2009	.43	.43	.43	.43	1.72
2010	.44	.44	.44	.44	1.76
2011	.45	.45	.45	.55	1.90
2012	.36	.46	.46	.46	

BUSINESS: AGL Resources Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, and Virginia Natural Gas. Acquired Nicor in 2011. The utilities have more than 2.3 million customers in Georgia, Virginia, Tennessee, New Jersey, and Florida. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. BlackRock Inc. owns 6.8% of common stock; off./dir., less than 1.0% (3/12 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources reported mixed results in the third quarter. Revenues increased to $614 million (up 108% year over year); earnings were $0.08 a share compared to last year's $0.04-a-share loss. Still, earnings were lower than expected, and were hurt by a $16 million hedging loss. Revenues are expected to grow strongly in the fourth quarter, aided by the Nicor acquisition. Revenues and earnings, however, could be adversely affected if a warmer-than-usual winter occurs.

Hurricane Sandy may have a small negative effect on profits in the fourth quarter. AGL's subsidiary, Elizabethtown Gas, is located in central New Jersey, which took the brunt of the storm. Damages and losses due to wind and flooding were incurred, and revenue was lost due to customers losing power. The Virginia Natural Gas Company, another subsidiary that was projected to be in the storm's path, remained largely unaffected. The damage from the storm could have lingering effects on the top and bottom line in the fourth quarter.

AGL's subsidiaries continue to strive for growth. Atlanta Gas Light Co. recently inked an agreement that permits it to install five new compressed natural gas fueling stations throughout Georgia. The Nicor acquisition continues to be integrated, and costs savings are slowly being realized. Fourth-quarter earnings should be helped by these cost-savings initiatives.

We have lowered our Target Price Range from $55-$70 to $50-$65. Pressures from high supply in the natural gas market will hurt distributors and temper revenue and earnings gains, countering growth in new customers and projects.

This issue has retreated some since last report, increasing the dividend yield to 4.8% for new investors. We expect the payout to expand in 2013, as earnings continue to grow.

These shares' Timeliness rank is 3 (Average). AGL Resources will likely perform in line with the broader market over the next six to 12 months. However, those who seek dividend income should consider this issue due to its high yields, the likelihood of increased payouts and the Highest Safety rank of 1.

John E. Seibert III *December 7, 2012*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses):'99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late January.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2011: $1918 million, $16.40/share.
(E) In millions. (F) Excluding special dividends from the Nicor merger.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

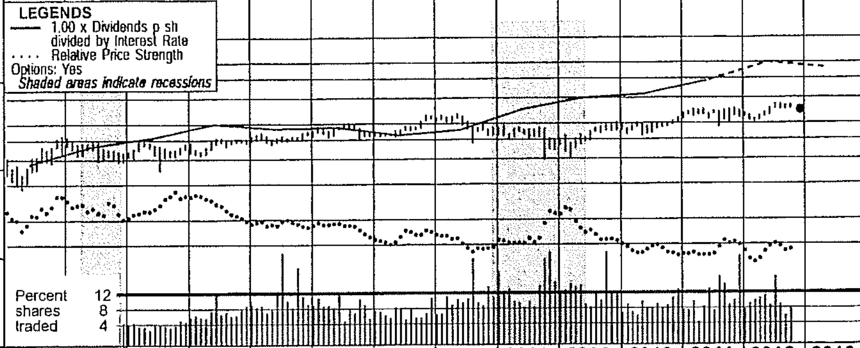
ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 34.78 | P/E RATIO 15.0 (Trailing: 15.1, Median: 14.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 2 Raised 8/17/12
SAFETY 2 Raised 12/16/05
TECHNICAL 3 Lowered 11/23/12
BETA .70 (1.00 = Market)

High:	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.6	37.3
Low:	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+15%)	7%
Low	30	(-15%)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	2	0	0	1	0
to Sell	0	0	1	0	0	1	0	2	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	132	127	112
to Sell	103	117	131
Hld's(000)	48646	50572	51653

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	10.8
3 yr.	47.3	48.5
5 yr.	61.9	25.2

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.82	54.39	46.50	61.75	75.27	66.03	79.52	53.69	53.12	48.15	*38.20*	*41.75*	Revenues per sh A	*63.10*
3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.29	4.64	4.72	*4.75*	*5.10*	"Cash Flow" per sh	*5.65*
1.45	1.71	1.58	1.72	2.00	1.94	2.00	1.97	2.16	2.28	2.10	*2.35*	Earnings per sh A B	*2.70*
1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	*1.40*	Div'ds Decl'd per sh C■	*1.48*
3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.51	6.02	8.90	*8.15*	*8.50*	Cap'l Spending per sh	*8.80*
13.75	16.66	18.05	19.90	20.16	22.01	22.60	23.52	24.16	24.98	*26.20*	*29.00*	Book Value per sh	*34.65*
41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.55	90.16	90.30	*90.00*	*91.00*	Common Shs Outst'g D	*103.00*
15.2	13.4	15.9	18.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9		Avg Ann'l P/E Ratio	*13.0*
.83	.76	.84	.86	.73	.84	.82	.83	.84	.90	1.01		Relative P/E Ratio	*.85*
5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%		Avg Ann'l Div'd Yield	*4.2%*
950.8	2799.9	2920.0	4973.3	8152.4	5898.4	7221.3	4969.1	4789.7	4347.6	3438.5	*3800*	Revenues ($mill) A	*6500*
59.7	79.5	86.2	135.8	162.3	170.5	180.3	179.7	201.2	199.3	192.2	*215*	Net Profit ($mill)	*280*
37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	*35.0%*	Income Tax Rate	*38.5%*
6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	*5.7%*	Net Profit Margin	*4.3%*
53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	*45.5%*	*45.0%*	Long-Term Debt Ratio	*49.0%*
46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	54.8%	50.6%	*54.5%*	*55.0%*	Common Equity Ratio	*51.0%*
1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	*4315*	*4800*	Total Capital ($mill)	*7000*
1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	*5475*	*5800*	Net Plant ($mill)	*6700*
6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	8.9%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.0%*
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	*8.0%*	*8.0%*	Return on Com Equity	*8.0%*
1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
82%	70%	77%	73%	63%	65%	65%	88%	62%	62%	*65%*	*59%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $2419.9 mill. **Due in 5 Yrs** $660.0 mill.
LT Debt $1956.3 mill. **LT Interest** $110.0 mill.
(LT interest earned: 3.1x; total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $17.7 mill.
Pfd Stock None
Pension Assets-9/11 $280.2 mill. Oblig. $429.4 mill.
Common Stock 90,173,217 shs. as of 8/3/12
MARKET CAP: $3.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	132.0	131.4	27.7
Other	743.2	879.6	748.0
Current Assets	875.2	1011.0	775.7
Accts Payable	266.2	291.2	178.2
Debt Due	486.2	208.8	463.6
Other	413.7	367.6	468.4
Current Liab.	1166.1	867.6	1110.2
Fix. Chg. Cov.	440%	432%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.5%	-3.5%	*3.5%*
"Cash Flow"	4.5%	4.5%	*3.5%*
Earnings	7.0%	4.0%	*4.0%*
Dividends	1.5%	1.5%	*1.5%*
Book Value	6.5%	4.5%	*6.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1716.3	1821.4	780.8	650.6	4969.1
2010	1292.9	1940.3	770.2	786.3	4789.7
2011	1133.3	1581.5	843.6	789.2	4347.6
2012	1084.0	1225.5	576.4	552.6	3438.5
2013	*1095*	*1300*	*725*	*680*	*3800*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.83	1.29	.02	d.17	1.97
2010	1.00	1.17	d.03	.02	2.16
2011	.81	1.40	.04	.01	2.26
2012	.68	1.12	.31	--	2.10
2013	*.74*	*1.36*	*.22*	*.03*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.325	.325	.325	.33	1.31
2009	.33	.33	.33	.335	1.33
2010	.335	.335	.335	.34	1.35
2011	.34	.34	.34	.345	1.37
2012	.345	.345	.345	.35	

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2011 gas volumes: 281.5 MMcf. Breakdown: 57%, residential; 32%, commercial; 7%, industrial; and 4% other. 2011 depreciation rate 3.3%. Has around 4,750 employees. Officers and directors own 1.5% of common stock (12/11 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

We believe that Atmos Energy will stage an earnings turnaround in the new fiscal year, which began on October 1st. The core natural gas distribution segment stands to benefit from a rise in throughput, if weather conditions cooperate (leading to a boost in consumption levels). Moreover, the other operations, including the natural gas marketing business and pipeline unit, ought to perform reasonably well, overall. As a result, we expect consolidated share net to climb about 12%, to $2.35, in fiscal 2013. Assuming additional expansion of operating margins, the bottom line could well advance roughly 5% or so, to $2.45 a share, the following year.

Steady, although unspectacular, results appear to be in store for the company over the 2015-2017 time frame. The utility ranks as one of the country's biggest natural gas-only distributors, boasting roughly three million customers across nine states. Furthermore, the other businesses, especially pipelines, possess healthy overall expansion prospects. Finally, we believe that the company will eventually resume its successful strategy of purchasing less efficient utilities and shoring up their profitability through expense-reduction efforts, rate relief, and aggressive marketing initiatives. (The last major transaction occurred in October, 2004, when Atmos Energy bought TXU Gas Company.) But given our exclusion of future acquisitions, because of size and timing issues, annual earnings-per-share growth may be in the mid-single-digit range over the coming three to five years.

The stock offers an appealing dividend yield, which is higher than the average of all gas utility equities tracked by *Value Line*. Our 2015-2017 projections indicate that further, albeit moderate, increases in the distribution are likely to take place. The payout ratio ought to remain within a manageable range (i.e., 50% to 60%). What's more, these shares currently hold a 2 (Above Average) rank for both Safety and Timeliness, as well as an excellent score for Price Stability. All things considered, a variety of investors might wish to take a look here.

Frederick L. Harris, III *December 7, 2012*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '03, d17¢; '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 27¢. Next egs. rpt. due early Feb. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	90

LACLEDE GROUP NYSE-LG

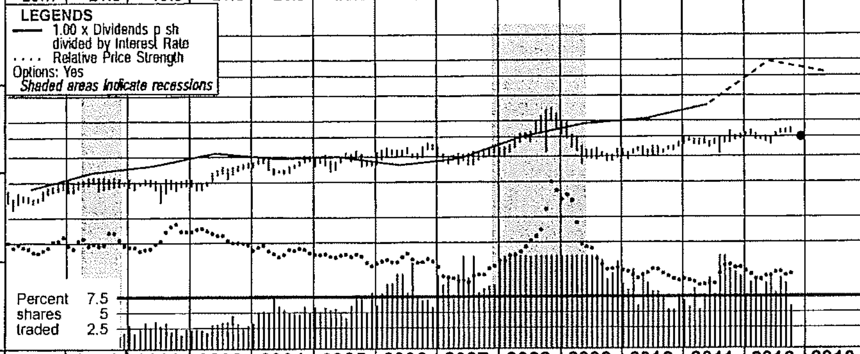
RECENT PRICE 39.89 | P/E RATIO 13.7 (Trailing: 14.3, Median: 14.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Lowered 9/23/11
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 11/23/12
BETA .55 (1.00 = Market)

High:	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3	37.8	42.8	44.0
Low:	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	29.3	30.8	32.9	36.5

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+50%)	14%
Low	45	(+15%)	6%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	64	62	62
to Sell	58	71	64
Hld's(000)	10812	11161	10921

Percent shares traded 7.5 / 5 / 2.5

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.2	10.8
3 yr.	54.8	48.5
5 yr.	48.2	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.76	*50.40*	Revenues per sh A	*52.00*
3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.82	4.58	*4.65*	"Cash Flow" per sh	*5.20*
1.87	1.64	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	*2.85*	Earnings per sh A B	*3.30*
1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	*1.74*	Div'ds Decl'd per sh C ■	*1.84*
2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.71	*2.85*	Cap'l Spending per sh	*3.00*
13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.60	*28.35*	Book Value per sh D	*33.00*
17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.62	*23.0*	Common Shs Outst'g E	*23.5*
11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.8	14.2	14.3	13.4	13.7	13.0	14.5		Avg Ann'l P/E Ratio	*15.5*
.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.81	.97		Relative P/E Ratio	*1.05*
5.6%	5.8%	5.4%	5.8%	8.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%		Avg Ann'l Div'd Yield	*3.8%*

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	*1150*	Revenues ($mill) A	*1225*
22.4	34.6	36.1	40.1	50.5	49.8	57.8	64.3	54.0	63.8	63.1	*65.0*	Net Profit ($mill)	*78.0*
35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	32.0%	*31.0%*	Income Tax Rate	*33.0%*
3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	*5.6%*	Net Profit Margin	*6.4*
47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	36.0%	*38.5%*	Long-Term Debt Ratio	*37.5%*
52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	64.0%	*61.5%*	Common Equity Ratio	*62.5%*
546.6	605.0	737.4	707.9	798.9	784.5	876.1	906.3	899.9	937.7	941.0	*1050*	Total Capital ($mill)	*1240*
594.4	621.2	646.9	679.5	763.8	793.8	823.2	855.9	884.1	928.7	1019.3	*1025*	Net Plant ($mill)	*1100*
6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	6.5%	*7.5%*	Return on Total Cap'l	*7.5%*
7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.6%	*9.5%*	Return on Shr. Equity	*10.0%*
7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.6%	*9.5%*	Return on Com Equity	*10.0%*
NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	*4.0%*	Retained to Com Eq	*4.5%*
NMF	74%	73%	72%	59%	63%	56%	53%	64%	56%	60%	*61%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $364.4 mill. **Due in 5 Yrs** $50.0 mill.
LT Debt $339.4 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 4.6x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/11 $248.0 mill. Oblig. $384.2 mill.

Pfd Stock None
Common Stock 22,262,000 shs. as of 9/30/12

MARKET CAP: $900 million (Small Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	86.9	43.3	27.5
Other	327.3	325.8	315.5
Current Assets	414.2	369.1	343.0
Accts Payable	95.6	96.6	89.5
Debt Due	154.6	46.0	25.0
Other	83.7	89.3	137.6
Current Liab.	333.9	231.9	252.1
Fix. Chg. Cov.	391%	463%	242%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.0%	.5%	*-6.5%*
"Cash Flow"	5.0%	7.0%	*2.5%*
Earnings	6.5%	6.0%	*3.0%*
Dividends	1.5%	2.5%	*2.5%*
Book Value	5.0%	6.5%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	674.3	659.1	309.9	251.9	1895.2
2010	491.2	635.3	324.5	284.0	1735.0
2011	444.2	543.8	344.3	271.0	1603.3
2012	410.9	358.2	186.9	169.5	1125.5
2013	*365*	*400*	*210*	*175*	*1150*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.42	1.40	.31	d.22	2.92
2010	1.03	1.26	.21	d.07	2.43
2011	1.05	1.25	.69	d.13	2.86
2012	1.12	1.32	.38	d.03	2.79
2013	*1.20*	*1.35*	*.40*	*d.10*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.375	1.50
2009	.385	.385	.385	.385	1.54
2010	.395	.395	.395	.395	1.58
2011	.405	.405	.405	.405	1.62
2012	.415	.415	.415	.415	

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 628,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Utility therms sold and transported in fiscal 2012: 1.0 bill. Revenue mix for regulated operations: residential, 64; commercial and industrial, 21%; transportation, 2%; other, 13%. Has around 1,640 employees. Officers and directors own approximately 8% of common shares (1/12 proxy). Chairman: William E. Nasser; CEO: Suzanne Sitherwood. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group's fourth-quarter results were better than expected (Years end September). Revenues decreased to $169.5 million, due to lower commodities costs, which were passed through to natural gas customers. Losses were narrowed to $0.03 a share compared to last year's deficit of $0.13. Margin expansion (5.6% in 2012 versus 4.0% in 2011) played a major factor in this year's earnings decreasing only slightly, even though there was a large decline in sales.

Increases in infrastructure replacement spending are a key component of Laclede's growth strategy. Over half of the $115 million spent on infrastructure is eligible to be recovered through the Infrastructure System Replacement Surcharge (ISRS), which charges customers for infrastructure replacement and improvement. This program leads to higher fixed revenues with greater margins, which allows for more consistent financial results.

Laclede is investing in emerging technologies in its non-regulated division, such as compressed natural gas (CNG) for vehicles. This segment advanced 37% over fiscal 2011. Commercial vehicle fleets, like the one at AT&T, are increasingly using CNG as an economical fuel source. As this trend plays out, Laclede's earnings will increasingly come from the nonregulated gas division, which should grow margins further.

Laclede raised its quarterly dividend to $0.425 a share, increasing the payout by 2.4% per year. The share price has come down since our last report bringing the yield up to 4.3%. This is well covered by earnings. Dividend growth has the potential to be quite noticeable over the next few years. This is the 10th year in a row that Laclede has raised its dividend, and this trend is likely to persist.

Laclede has a Timeliness rank of 3 (Average). This issue is likely to track the broader averages over the next six to 12 months. Its Above-Average Safety rank and growing dividend may appeal to income investors. This dividend also has the potential to be one of the strongest in the natural gas distribution field, thanks to the company's stronger-than-average cash flow potential.

John E. Seibert III *December 7, 2012*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late January.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '11: $429.9 mill., $19.17/sh.
(E) In millions.
(F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	80

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 40.33 | P/E RATIO 14.1 (Trailing: 13.4 Median: 15.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 9/14/12
SAFETY 1 Raised 9/15/06
TECHNICAL 3 Lowered 11/30/12
BETA .65 (1.00 = Market)

High:	21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4	44.1	50.5	50.3
Low:	16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	30.0	33.5	39.6	38.5

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

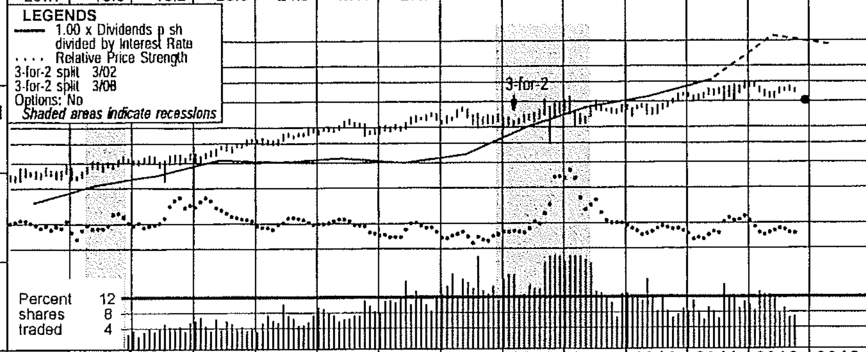
	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	45	(+10%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	2	0	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	66	75	68
to Sell	65	71	80
Hld's(000)	24285	24119	23904



% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.2	10.8
3 yr.	40.2	46.5
5 yr.	61.0	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
13.48	17.31	17.73	22.65	29.42	51.22	44.11	62.29	60.89	76.19	79.83	72.82	90.74	62.34	64.10	72.60	54.16	*70.00*	Revenues per sh A	*78.50*
1.48	1.63	1.74	1.86	1.99	2.12	2.14	2.38	2.50	2.62	2.73	2.44	3.62	3.16	3.26	3.40	*3.74*	*3.85*	"Cash Flow" per sh	*4.45*
.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	2.40	2.46	2.58	2.71	*2.90*	Earnings per sh B	*3.40*
.89	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	1.24	1.36	1.44	1.52	*1.60*	Div'ds Decl'd per sh C■	*1.68*
1.19	1.15	1.07	1.21	1.23	1.10	1.02	1.14	1.45	1.28	1.28	1.46	1.72	1.81	2.10	2.26	*2.00*	*2.00*	Cap'l Spending per sh	*2.00*
6.73	8.92	7.26	7.57	8.29	8.80	8.71	10.28	11.25	10.60	15.00	15.50	17.28	16.59	17.82	18.73	*18.15*	*19.10*	Book Value per sh D	*24.20*
40.69	40.23	40.07	39.92	39.59	40.00	41.50	40.85	41.61	41.32	41.44	41.81	42.06	41.59	41.17	41.45	41.53	*40.00*	Common Shs Outst'g E	*40.00*
13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	18.8	16.8		Avg Ann'l P/E Ratio	*14.0*
.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.08		Relative P/E Ratio	*.95*
5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.3%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $812.8 mill. **Due in 5 Yrs** $214.3 mill.
LT Debt $525.2 mill. **LT Interest** $19.6 mill.
Incl. $85.8 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/12 $207.8 mill. Oblig. $332.2 mill.
Pfd Stock None

Common Stock 41,689,123 shs. as of 11/23/12
MARKET CAP: $1.7 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	2592.5	2639.3	3009.2	2248.9	*2800*	Revenues ($mill) A	*3060*
56.8	65.4	71.6	74.4	78.5	85.3	113.9	101.0	101.8	106.5	*112*	*120*	Net Profit ($mill)	*140*
38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	27.1%	41.4%	30.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	3.9%	3.9%	3.5%	*5.0%*	*4.3%*	Net Profit Margin	*4.5%*
50.8%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	39.8%	37.2%	35.5%	39.2%	*39.5%*	Long-Term Debt Ratio	*34.0%*
49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	60.2%	82.8%	64.5%	60.8%	*60.5%*	Common Equity Ratio	*66.0%*
732.4	676.8	783.8	755.3	954.0	1026.0	1182.1	1144.8	1154.4	1203.1	1339.0	*1265*	Total Capital ($mill)	*1470*
756.4	852.6	880.4	905.1	934.9	970.9	1017.3	1064.4	1135.7	1295.9	1484.9	*1350*	Net Plant ($mill)	*1430*
8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	9.7%	9.7%	9.7%	*9.5%*	*10.5%*	Return on Total Cap'l	*10.0%*
15.7%	15.8%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	*14.0%*	*16.0%*	Return on Shr. Equity	*14.0%*
15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	*14.0%*	*16.0%*	Return on Com Equity	*14.0%*
6.9%	7.7%	7.8%	8.5%	8.3%	3.6%	9.5%	7.2%	6.7%	6.2%	*6.0%*	*7.5%*	Retained to Com Eq	*7.5%*
58%	51%	49%	50%	50%	64%	40%	50%	52%	55%	*56%*	*53%*	All Div'ds to Net Prof	*49%*

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	.9	7.4	4.5
Other	784.1	725.0	642.8
Current Assets	785.0	732.4	647.3
Accts Payable	47.3	66.0	265.8
Debt Due	178.9	166.9	287.6
Other	479.6	470.5	99.7
Current Liab.	705.8	703.4	653.1
Fix. Chg. Cov.	700%	700%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	7.0%	-1.5%	*2.5%*
"Cash Flow"	5.0%	4.5%	*5.0%*
Earnings	7.5%	7.0%	*5.5%*
Dividends	6.0%	8.0%	*4.0%*
Book Value	8.0%	7.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	801.3	937.5	441.1	412.6	2592.5
2010	609.6	918.4	479.8	631.5	2639.3
2011	713.2	977.0	648.1	670.9	3009.2
2012	642.4	612.9	425.1	568.5	2248.9
2013	*790*	*765*	*575*	*670*	*2800*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.77	1.71	.03	d.12	2.40
2010	.66	1.55	.28	d.03	2.46
2011	.71	1.62	.23	.02	2.58
2012	1.09	1.79	.10	d.27	2.71
2013	*1.15*	*1.84*	*.15*	*d.24*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.31	.31	.31	.31	1.24
2010	.34	.34	.34	.34	1.36
2011	.36	.36	.36	.36	1.44
2012	.38	.38	.38	.38	1.52
2013	.40				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 494,964 customers at 9/30/11 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2011 volume: 178 bill. cu. ft. (5% interruptible, 35% residential and commercial and electric utility, 60% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2011 dep. rate: 2.2%. Has 891 empls. Off./dir. own about 1.1% of common (12/11 Proxy). Chrmn., CEO & Pres.: Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources posted a mixed bag of financial results for fiscal 2012 (ended September 30th). Indeed, the top line declined approximately 25% on a year-over-year basis. This reflected diminished volumes at both the utility and nonutility divisions. However, this was not alarming, being largely due to lower year-to-year comparable natural gas prices. Overall, management was successful at trimming unnecessary expenses, thereby boosting profitability for the year. And, on balance, NJR logged a modest 5% earnings advance, to $2.71 a share. However, this was slightly lower than we had previously anticipated. Consequently,

We have reduced our top- and bottom-line estimates for 2013 accordingly. Helped by low natural gas prices, New Jersey Resources has been quite successful at growing the number of customer accounts at the New Jersey Natural Gas regulated utility division. That unit comprises the bulk of the company's business mix, and is expected to add 6,000 to 7,000 new customers this year alone. Elsewhere, the NJR Clean Energy Ventures segment has multiple capital projects for alternative energy investments in its pipeline. On the downside, the NJR Energy services unit will likely continue to experience difficulties this year, as historically low natural gas prices and reduced volatility weigh on the wholesale market's profitability. Meanwhile, cost-cutting efforts that helped to boost the bottom line in 2012, will not be as effective with sustained top-line weakness this year. Thus, we have reduced our earnings estimate by $0.25, to $2.90 a share, for fiscal 2013.

The board recently approved a quarterly divided increase of about 5%, to $0.40 a share. This payout came on the heels of the regularly scheduled fourth-quarter dividend, due to concerns that the tax rate on dividends may rise next year.

These neutrally ranked shares are trading down roughly 13% in price since our September review. The bulk of this move likely stemmed from concerns for how the effects of Hurricane Sandy may weigh on the company's operations, as well as general concerns over higher taxes on dividends and capital gains.

Bryan J. Fong *December 7, 2012*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late Jan.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2011: $434.2 million, $10.48/share.
(E) In millions, adjusted for splits.

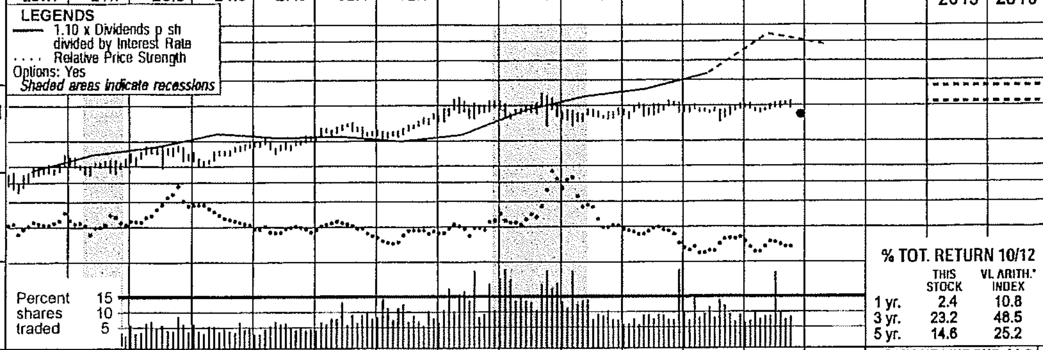
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	50

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE	43.28	P/E RATIO	18.5 (Trailing: 18.4 Median: 17.0)	RELATIVE P/E RATIO	1.15	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 3 Raised 9/21/12
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Lowered 12/7/12
BETA .55 (1.00 = Market)

High:	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	46.5	50.9	49.0	50.8
Low:	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	37.7	41.1	39.6	41.0



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	12%
Low	50	(+15%)	8%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	2	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	72	69	70
to Sell	43	58	51
Hld's(000)	16071	16355	16429

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.4	10.8
3 yr.	23.2	48.5
5 yr.	14.6	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.86	15.82	18.77	18.17	21.09	25.76	25.07	23.57	25.89	33.01	37.20	39.13	39.16	38.17	30.56	31.72	*29.25*	*29.10*	Revenues per sh	*30.55*
3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	*4.50*	*4.60*	"Cash Flow" per sh	*4.95*
1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.88	2.11	2.35	2.76	2.57	2.83	2.73	2.39	*2.25*	*2.45*	Earnings per sh A	*3.15*
1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	*1.79*	*1.83*	Div'ds Decl'd per sh B ■	*1.96*
3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	*6.60*	*7.00*	Cap'l Spending per sh	*8.10*
15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	*26.95*	*27.35*	Book Value per sh D	*27.75*
22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	*27.00*	*27.50*	Common Shs Outst'g C	*28.00*
11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.20	*Value Line*		Relative P/E Ratio	*1.15*
5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $817.5 mill. Due in 5 Yrs $200 mill.
LT Debt $641.7 mill. LT Interest $45.0 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/11 $216 mill.
Oblig. $391.1 mill.

Pfd Stock None

Common Stock 26,902,000 shares

MARKET CAP $1.2 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	812.1	848.8	*790*	*800*	Revenues ($mill)	*855*
43.8	46.0	50.6	58.1	65.2	74.5	68.5	75.1	72.7	63.9	*60.0*	*70.0*	Net Profit ($mill)	*90.0*
34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	*38.5%*	*36.0%*	Income Tax Rate	*32.5%*
6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	*8.1%*	*8.8%*	Net Profit Margin	*10.3%*
47.8%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*48.5%*
51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	*53.0%*	*53.0%*	Common Equity Ratio	*52.5%*
937.3	1006.8	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	*1370*	*1410*	Total Capital ($mill)	*1515*
995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	1654.2	1693.9	*1985*	*1895*	Net Plant ($mill)	*1895*
5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.3%	7.0%	8.2%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	*8.5%*	*9.5%*	Return on Shr. Equity	*11.5%*
8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	*8.5%*	*9.0%*	Return on Com Equity	*11.5%*
1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	*2.5%*	*3.0%*	Retained to Com Eq	*4.0%*
79%	72%	69%	63%	59%	52%	59%	56%	61%	73%	*80%*	*75%*	All Div'ds to Net Prof	*62%*

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	3.5	5.8	5.7
Other	326.8	342.9	192.2
Current Assets	330.3	348.7	197.9
Accts Payable	93.2	86.3	61.3
Debt Due	267.4	181.6	175.8
Other	107.6	146.6	108.3
Current Liab.	468.2	414.5	345.4
Fix. Chg. Cov.	366%	334%	344%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	1.0%	-1.5%
"Cash Flow"	3.0%	3.5%	-0.5%
Earnings	4.0%	4.5%	3.0%
Dividends	3.0%	4.5%	2.5%
Book Value	4.0%	4.0%	1.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	437.4	149.1	116.9	309.3	1012.7
2010	286.5	162.4	95.1	268.1	812.1
2011	323.1	161.2	93.3	271.2	848.8
2012	317.5	106.6	89.8	*276.1*	*790*
2013	*315*	*140*	*90*	*255*	*800*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.78	.12	d.25	1.18	2.83
2010	1.64	.26	d.28	1.11	2.73
2011	1.53	.08	d.31	1.09	2.39
2012	1.51	.05	d.39	*1.08*	*2.25*
2013	*1.50*	*.15*	*d.25*	*1.05*	*2.45*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.395	1.52
2009	.395	.395	.395	.415	1.60
2010	.415	.415	.415	.435	1.68
2011	.435	.435	.435	.445	1.75
2012	.445	.445	.445	.455	

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 681,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 57%; commercial, 26%; industrial, gas transportation, and other, 17%. Employs 1,061. BlackRock Inc. owns 7.8% of shares; officers and directors, 1.7% (4/12 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Gas Co.'s third-quarter results were mixed. Revenues decreased to $89.8 million, down 4% year over year. Losses narrowed to $0.29 a share compared to last year's $0.31. Margins expanded while sales declined. Increases in natural gas storage income (up 8%) likely will have a small but positive effect on profits and sales.

NW Natural received mixed results from a base rate case filed in Oregon. The Oregon Public Utility Commission (PUC) allowed the company to collect higher fixed charges, increasing revenues by $8.7 million. The PUC also lowered rates that NW Natural charges for natural gas. Although margins should decline as a result of this rate decrease, total volume should increase over the next few years, somewhat limiting the downside effect. As a result, we have lowered our earnings estimate for 2012 to $2.25 a share from $2.45. The higher fixed charges could lower earnings variability. Pension cost base-rate decisions were deferred by the PUC, but the outcome will have an effect on future profitability.

NW Natural is focused on increasing its industrial customer base. By filing to lower the base rate by 14%, the company would entice more businesses to switch to natural gas for their processes. This would potentially grow and diversify the customer base while increasing revenues. The company is also on track with its joint venture with Encana in the Jonah field, which should produce 8%-10% of the annual natural gas requirements. Both these initiatives are crucial to long-term growth.

NW Natural has raised its annual dividend to $1.82 a share. This is the 57th consecutive year that the company has increased its dividend and this trend is likely to continue. The stock retreat since our last report and the dividend increase have caused the yield to expand, but it is still below average for gas utilities.

NW Natural has a Timeliness rank of 3 (Average). Although this issue has below market average appreciation potential, conservative investors with an income objective should consider this issue because it has a high and growing yield and Highest Safety rank (1); however, this issue is not for performance-minded investors.

John E. Seibert III *December 7, 2012*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 8¢; Next earnings report due late January.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2011: $371.4 million, $13.88/share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	90

PSC Case No. 2013-00167
PSC Set 2 DR No. 26
Attachment A
Respondent: P. R. Moul

PIEDMONT NAT'L. GAS NYSE-PNY

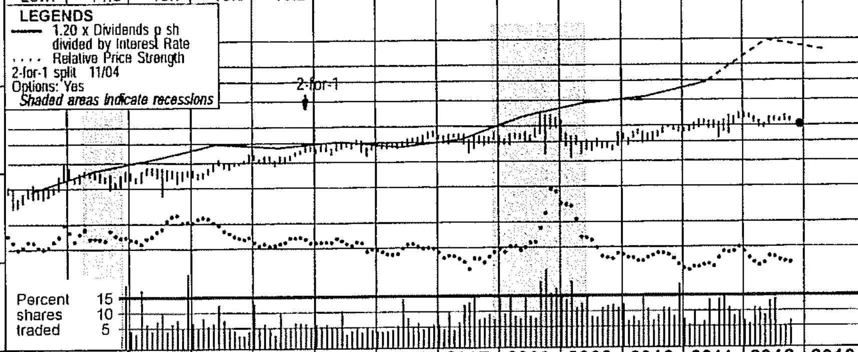
RECENT PRICE 30.34 | P/E RATIO 17.8 (Trailing: 19.4 Median: 18.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 6/22/12
SAFETY 2 New 7/27/90
TECHNICAL 2 Raised 11/2/12
BETA .65 (1.00 = Market)

High:	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6			
Low:	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.5			

Target Price Range 2015 | 2016 | 2017

LEGENDS
—— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 11/04
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+30%)	11%
Low	30	(Nil)	4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	2	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	85	68	84
to Sell	85	92	74
Hld's(000)	32579	32684	33222

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.1	10.8
3 yr.	52.2	48.5
5 yr.	50.0	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	22.36	21.48	19.83	15.75	17.85	Revenues per sh A	20.10
1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	3.01	2.91	2.99	3.05	3.20	"Cash Flow" per sh	3.45
.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	1.57	1.60	1.70	Earnings per sh AB	1.85
.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	1.19	1.23	Div'ds Decl'd per sh C■	1.35
1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.18	1.85	2.50	2.74	1.85	2.47	1.76	2.75	3.37	7.75	7.85	Cap'l Spending per sh	8.10
6.53	6.95	7.45	7.86	8.28	8.63	8.91	9.38	11.15	11.53	11.83	11.99	12.11	12.67	13.35	13.79	13.85	14.00	Book Value per sh D	14.60
59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	78.70	74.61	73.23	73.26	73.27	72.28	72.32	71.00	70.00	Common Shs Outst'g E	68.00
13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.8	17.9	19.2	18.7	18.2	15.4	17.1	18.9	19.9		Avg Ann'l P/E Ratio	18.0
.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	1.28		Relative P/E Ratio	1.20
4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	4.1%	4.2%	3.9%	3.7%		Avg Ann'l Div'd Yield	3.9%

CAPITAL STRUCTURE as of 7/31/12
Total Debt $1175.0 mill. Due in 5 Yrs $175.0 mill.
LT Debt $975.0 mill. LT Interest $46.1 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/11 $259.5 mill. Oblig. $236.6 mill.

Pfd Stock None

Common Stock 72,076,431 shs. as of 9/4/12

MARKET CAP: $2.2 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
832.0	1220.8	1529.7	1781.1	1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	1120	1250	Revenues ($mill) A	1365
62.2	74.4	95.2	101.3	97.2	104.4	110.0	122.8	111.8	113.6	115	120	Net Profit ($mill)	125
33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	25.0%	25.0%	Income Tax Rate	25.0%
7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	10.2%	9.6%	Net Profit Margin	9.3%
43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	49.0%	50.0%	Long-Term Debt Ratio	50.0%
56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	50.0%	50.0%	Common Equity Ratio	50.0%
1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	1960	1955	Total Capital ($mill)	1995
1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	2900	2950	Net Plant ($mill)	3050
7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	8.0%	8.0%	Return on Total Cap'l	8.5%
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	11.5%	12.0%	Return on Shr. Equity	12.5%
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	11.5%	12.0%	Return on Com Equity	12.5%
1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	3.0%	3.5%	Retained to Com Eq	3.5%
83%	74%	66%	68%	74%	70%	69%	64%	72%	73%	74%	72%	All Div'ds to Net Prof	73%

CURRENT POSITION ($MILL.)

	2010	2011	7/31/12
Cash Assets	5.6	6.8	5.7
Other	322.2	279.2	283.4
Current Assets	327.8	286.0	289.1
Accts Payable	115.7	129.7	117.9
Debt Due	302.0	331.0	200.0
Other	80.9	72.9	80.4
Current Liab.	498.6	534.1	398.3
Fix. Chg. Cov.	323%	323%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	-1.5%	-1.0%
"Cash Flow"	5.5%	4.0%	2.5%
Earnings	5.0%	4.5%	2.5%
Dividends	4.5%	4.0%	3.5%
Book Value	5.0%	3.0%	1.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	779.6	455.4	180.3	222.8	1638.1
2010	673.7	472.9	211.6	194.1	1552.3
2011	652.0	392.6	197.3	192.0	1433.9
2012	471.8	308.4	161.1	178.7	1120
2013	505	340	195	210	1250

Fiscal Year Ends	EARNINGS PER SHARE A B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	1.10	.73	d.10	d.06	1.67
2010	1.14	.65	d.13	d.13	1.55
2011	1.16	.66	d.12	d.13	1.57
2012	1.05	.70	d.06	d.09	1.60
2013	1.18	.70	d.09	d.09	1.70

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.25	.26	.26	.26	1.03
2009	.26	.27	.27	.27	1.07
2010	.27	.28	.28	.28	1.11
2011	.28	.29	.29	.29	1.15
2012	.29	.30	.30	.30	

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 968,188 customers in North Carolina, South Carolina, and Tennessee. 2011 revenue mix: residential (48%), commercial (27%), industrial (7%), other (20%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 60.0% of revenues. '11 deprec. rate: 3.2%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,782 employees. Off./dir. own about 1.2% of common stock, BlackRock; 7.6% (1/12 proxy). Chrmn., CEO, & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas likely posted a mixed bag of financial results for fiscal 2012 (ended October 31st). Indeed, we expect a year-to-year top-line decline of approximately 22%. This is largely a reflection of lower pass-through costs for natural gas. Meanwhile, on the profitability front, the company has been successful in trimming its cost of goods sold for the bulk of the year, and we expect that trend continued in the fourth quarter and for the year, as a whole. Customer additions were another boon to the bottom line. At the end of the third quarter, Piedmont had added more than 8,700 accounts to its system. Elsewhere, gains ought to have stemmed from a rise in income from equity-method investments, as higher contributions come in from the energy services and pipeline divisions. Combined, we think PNY's 2012 share-net figure ticked about 2% higher, to $1.60.

Capital projects augur well for prospects down the road. At this point, Piedmont finished the first four power generation delivery projects for Duke Energy. The fifth project, related to the Sutton Facility, is well under way, and has a targeted in-service date of June, 2013. These developments equate to an investment of $500 million, and they are boosting throughput on the Cardinal Pipeline.

We look for steady top- and bottom-line advances in fiscal 2013. This ought to be supported by continued customer additions, a wider geographic footprint due to capital expenditures, and a diligent eye on efficiency initiatives. And a recently announced 24% equity stake in Constitution Pipeline Company, LLC., a natural gas pipeline project slated to be in service in 2015 adds to the PNY's prospects.

However, the financial position has deteriorated a bit over the course of the year. Cash reserves declined 16%, through the end of the third quarter (the last period for which financial information was available), to just under $6 million. And the company has taken on about 45% more long-term debt over this time frame.

These neutrally ranked shares have remained relatively steady since our September review. And PNY's yield is on par with the *Value Line* average for the utility group.

Bryan J. Fong *December 7, 2012*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '97, (2¢); '10, 41¢. Next earnings report due mid Dec. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid early-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2011: $527.8 million, $7.29/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

SOUTH JERSEY INDS. NYSE-SJI

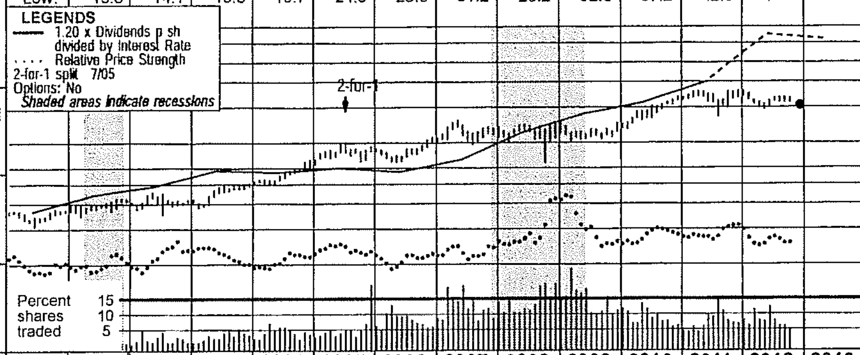
RECENT PRICE 48.96 | P/E RATIO 15.2 (Trailing: 15.7, Median: 15.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 11/23/12
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 10/19/12
BETA .65 (1.00 = Market)

High:	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8	54.2	58.0	58.0
Low:	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.0	37.2	42.8	45.8

Target Price Range 2015 | 2016 | 2017

LEGENDS
—— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+45%)	12%
Low	55	(+10%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	3	0	1	3	0	3	2

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	59	68	78
to Sell	60	64	55
Hld's(000)	17847	17213	18018

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.3	10.8
3 yr.	56.9	48.5
5 yr.	57.3	25.2

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.30	32.36	28.37	30.97	27.42	**23.00**	**26.45**	Revenues per sh	33.35
	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.48	3.72	4.21	4.46	**4.50**	**4.75**	"Cash Flow" per sh	6.25
	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	2.38	2.70	2.89	**3.15**	**3.35**	Earnings per sh A	4.50
	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.22	1.36	1.50	**1.65**	**1.82**	Div'ds Decl'd per sh B ■	2.30
	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.38	2.67	3.21	2.51	1.88	2.08	3.67	5.59	8.39	**6.20**	**6.45**	Cap'l Spending per sh	7.20
	8.03	8.43	8.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	18.24	19.08	20.66	**23.00**	**24.60**	Book Value per sh C	27.80
	21.51	21.54	21.58	22.30	23.00	23.72	24.41	28.46	27.76	28.98	29.33	29.81	29.73	29.80	29.87	30.21	**31.50**	**32.50**	Common Shs Outst'g D	36.00
	13.3	13.8	21.2	13.3	13.0	13.8	13.5	13.3	14.1	16.8	11.9	17.2	15.9	15.0	16.8	18.4	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.0
	.83	.80	1.10	.78	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.16	estimates		Relative P/E Ratio	.95
	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.8%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%			Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $906.8 mill. Due in 5 Yrs $434.0 mill.
LT Debt $566.4 mill. LT Interest $16.0 mill.
(Total interest coverage: 6.3x)

Pension Assets-12/11 $116.7 mill.
Oblig. $195.0 mill.

Pfd Stock None

Common Stock 31,262,570 common shs.
as of 11/1/12

MARKET CAP: $1.5 billion (Mid Cap)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
	505.1	696.8	819.1	921.0	931.4	956.4	962.0	845.4	925.1	828.6	**725**	**860**	Revenues ($mill)	1200
	29.4	34.6	43.0	48.6	72.0	61.6	67.7	71.3	81.0	87.0	**100**	**105**	Net Profit ($mill)	160
	41.4%	40.8%	40.9%	41.5%	41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	**20.0%**	**25.0%**	Income Tax Rate	30.0%
	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	**13.8%**	**12.2%**	Net Profit Margin	13.3%
	53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	38.5%	37.4%	40.5%	**44.0%**	**43.0%**	Long-Term Debt Ratio	43.0%
	48.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	**56.0%**	**57.0%**	Common Equity Ratio	57.0%
	512.5	608.4	675.0	710.3	801.1	839.0	848.0	856.4	910.1	1048.3	**1300**	**1400**	Total Capital ($mill)	1750
	666.6	748.3	799.9	877.3	920.0	948.9	982.6	1073.1	1193.3	1352.4	**1480**	**1600**	Net Plant ($mill)	1900
	7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	**8.5%**	**8.0%**	Return on Total Cap'l	9.5%
	12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	**14.0%**	**13.0%**	Return on Shr. Equity	16.0%
	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	**14.0%**	**13.0%**	Return on Com Equity	16.0%
	4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	**6.5%**	**5.5%**	Retained to Com Eq	7.5%
	62%	57%	52%	50%	37%	48%	49%	51%	50%	52%	**52%**	**56%**	All Div'ds to Net Prof	52%

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	2.4	7.5	4.2
Other	421.4	333.1	319.6
Current Assets	423.8	340.6	323.8
Accts Payable	165.2	153.7	111.1
Debt Due	362.1	323.6	340.4
Other	113.2	110.7	101.3
Current Liab.	640.5	588.0	552.8
Fix. Chg. Cov.	532%	505%	570%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-1.5%	2.5%
"Cash Flow"	8.0%	8.0%	7.0%
Earnings	9.5%	7.0%	9.0%
Dividends	6.5%	9.5%	9.0%
Book Value	10.5%	7.0%	6.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	362.2	134.5	127.1	221.6	845.4
2010	329.3	151.6	160.7	283.5	925.1
2011	331.9	160.5	137.6	198.6	828.6
2012	274.8	121.9	112.0	**216.3**	**725**
2013	**305**	**150**	**150**	**255**	**860**

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.46	.15	d.06	.83	2.38
2010	1.49	.24	.10	.87	2.70
2011	1.63	.20	.01	1.05	2.89
2012	1.65	.28	.13	**1.09**	**3.15**
2013	**1.70**	**.30**	**.15**	**1.20**	**3.35**

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	--	.270	.270	.568	1.11
2009	--	.298	.298	.628	1.22
2010	--	.330	.330	.695	1.36
2011	--	.365	.365	.768	1.50
2012	--	.403	.403	.845	

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 347,725 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '11: residential, 41%; commercial, 20%; cogeneration and electric generation, 14%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 675 employees. Off./dir. control 1.0% of common shares; BlackRock Inc., 7.8% (3/12 proxy). Chrmn. & CEO: Edward Graham. Inc.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Telephone: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have pulled back somewhat over the past two months. Revenue declined for the third quarter, but that was largely due to a lower natural gas pricing environment. The mainstay utility segment reported a moderate top-line decline, and the nonutility businesses posted considerably lower revenues. But operating costs also declined, and the bottom-line picture was much brighter. Share net came in at $0.13, well above the prior-year tally.

The company appears to have made it through Hurricane Sandy in good shape. Flooding and high winds from the super storm dealt a significant blow to New Jersey residents. But service disruption at the utility was minimal, and SJI's nonutility energy projects experienced mostly superficial damage.

We look for moderate earnings growth going forward. We expect healthy results from most of SJI's businesses. Utility South Jersey Gas ought to benefit from modest customer growth going forward. Natural gas remains the fuel of choice within its service territory, and the utility should continue to benefit from customer interest in converting from other sources of fuel. In addition, spending on infrastructure projects under the Capital Investment Recovery Tracker program ought to improve service and allow the utility to earn a good return on these investments. On the nonutility side, healthy demand for renewable and natural gas-fired energy projects should benefit the Retail Energy line. Efforts to reposition the marketing unit may also bear fruit.

The board of directors has increased the dividend by roughly 10%. The quarterly dividend is now $0.4425 per share, beginning with the December payout. The company cited strong recent performance and myriad growth opportunities as reasons for the hike. Dividend increases will likely continue in the coming years.

These shares are neutrally ranked for Timeliness. We anticipate higher revenues and earnings for the company by 2015-2017. Moreover, South Jersey earns good marks for Safety, Price Stability, and Earnings Predictability. This equity offers decent, and fairly well-defined, total return potential for the coming years.

Michael Napoli, CFA *December 7, 2012*

(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, $2.10; '08, $2.58; '09, $1.94; '10, $2.22; '11, $2.97. Excl. nonrecur. gain (loss): '01, $0.13; '08, $0.31; '09, ($0.44); '10, ($0.47); '11, $0.08. Excl gain (losses) from discont. ops.: '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Next egs. report due in February. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2011: $315.2 mill., $10.43 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	85

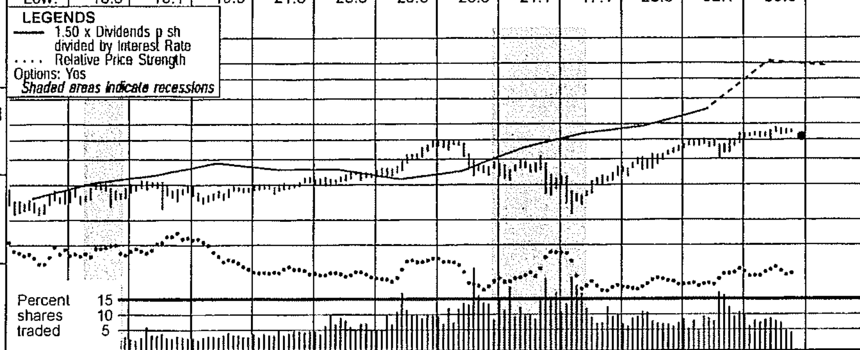
SOUTHWEST GAS NYSE-SWX

RECENT PRICE 41.30 | P/E RATIO 13.8 (Trailing: 15.2, Median: 17.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 11/16/12
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 8/10/12
BETA .75 (1.00 = Market)

High:	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	29.5	37.3	43.2	46.1	
Low:	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	17.1	26.3	32.1	39.0	

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+70%)	17%
Low	45	(+10%)	6%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	0	0	0	0	1
Options	0	0	2	0	0	2	0	0	1
to Sell	1	0	4	0	1	3	0	0	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	56	64	85
to Sell	95	79	70
Hld's(000)	34237	35127	34847

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	10.8
3 yr.	90.0	48.5
5 yr.	70.9	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.18	41.07	*42.25*	*43.10*	Revenues per sh	*52.00*
3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	*7.40*	*7.75*	"Cash Flow" per sh	*9.40*
.25	.77	1.85	1.27	1.21	1.15	1.18	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	2.43	*2.72*	*2.85*	Earnings per sh A	*3.75*
.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	1.06	*1.18*	*1.30*	Div'ds Decl'd per sh B†	*1.60*
8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.73	8.29	*7.85*	*8.50*	Cap'l Spending per sh	*9.60*
14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.62	28.66	*27.95*	*30.85*	Book Value per sh	*36.00*
26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	45.09	45.56	45.96	*46.50*	*47.00*	Common Shs Outst'g C	*50.00*
69.3	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	15.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
4.34	1.39	.89	1.20	1.04	.97	1.09	1.09	.76	1.10	.88	.92	1.22	.81	.89	.99	*Value Line*		Relative P/E Ratio	*1.00*
4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	1893.8	1830.4	1887.2	*1965*	*2025*	Revenues ($mill)	*2600*
38.6	38.5	58.9	48.1	80.5	83.2	61.0	87.5	103.9	112.3	*125*	*135*	Net Profit ($mill)	*190*
32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	34.0%	34.7%	36.2%	*36.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	4.6%	5.7%	6.0%	*6.4%*	*6.7%*	Net Profit Margin	*7.3%*
62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	53.5%	49.1%	43.2%	*49.0%*	*48.0%*	Long-Term Debt Ratio	*48.5%*
34.1%	34.0%	35.8%	38.2%	39.4%	41.9%	44.7%	46.5%	50.9%	56.8%	*51.0%*	*52.0%*	Common Equity Ratio	*51.5%*
1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	2371.4	2291.7	2155.9	*2550*	*2800*	Total Capital ($mill)	*3500*
1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	3034.5	3072.4	3218.9	*3320*	*3400*	Net Plant ($mill)	*3750*
4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	5.4%	6.1%	6.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	*9.5%*	*9.5%*	Return on Com Equity	*10.5%*
1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	4.1%	5.1%	5.3%	*5.5%*	*5.0%*	Retained to Com Eq	*6.0%*
70%	72%	49%	65%	42%	44%	63%	48%	43%	43%	*44%*	*45%*	All Div'ds to Net Prof	*42%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $1261.1 mill. **Due in 5 Yrs** $343.0 mill.
LT Debt $1256.0 mill. **LT Interest** $70.0 mill.
(Total interest coverage: 3.8x) (50% of Cap'l)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/11 $551.8 mill. **Oblig.** $832.8 mill.
Pfd Stock None

Common Stock 46,140,788 shs. as of 10/26/12

MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	116.1	21.9	22.1
Other	329.8	439.7	327.7
Current Assets	445.9	461.6	349.8
Accts Payable	165.5	186.8	90.6
Debt Due	75.1	322.6	5.1
Other	356.4	338.2	389.5
Current Liab.	597.0	847.6	465.2
Fix. Chg. Cov.	299%	359%	375%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-1.5%	*4.0%*
"Cash Flow"	3.5%	3.0%	*6.5%*
Earnings	6.0%	6.5%	*9.0%*
Dividends	2.0%	4.0%	*8.0%*
Book Value	4.5%	5.0%	*6.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	689.9	387.6	317.5	498.8	1893.8
2010	668.8	385.8	307.7	468.1	1830.4
2011	628.4	388.5	352.6	517.7	1887.2
2012	657.6	409.8	371.8	*525.8*	*1965*
2013	*670*	*420*	*390*	*545*	*2025*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.12	d.01	d.18	1.01	1.94
2010	1.42	d.02	d.11	.98	2.27
2011	1.48	.09	d.34	1.19	2.43
2012	1.70	d.08	d.09	*1.19*	*2.72*
2013	*1.80*	*.10*	*d.30*	*1.25*	*2.85*

Calendar	QUARTERLY DIVIDENDS PAID B† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.215	.225	.225	.225	.89
2009	.225	.238	.238	.238	.94
2010	.238	.250	.250	.250	.99
2011	.250	.265	.265	.265	1.05
2012	.265	.295	.295	.295	

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.9 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2011 margin mix: residential and small commercial, 86%; large commercial and industrial, 4%; transportation, 10%. Total throughput: 2.1 billion therms. Sold PriMerit Bank, 7/96. Has 5,754 employees. Off. & Dir. own 1.6% of common stock; BlackRock Inc., 8.5%; GAMCO Investors, Inc., 8.3%; T. Rowe Price Associates, Inc., 6.7% (3/12 Proxy). Chairman: Michael J. Melarkey. CEO: Jeffrey W. Shaw. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas reported improved results for the third quarter. Revenues increased at a moderate clip, and the company posted a much lower share loss for the interim, partly because Southwest experienced healthy growth in the construction business. Utility revenues were roughly flat, compared with the prior-year period, but were supported by higher rates in Arizona. Efforts to control operating costs benefited the bottom line. We anticipate healthy results for the fourth quarter, and greater revenues and share net for full-year 2012.

The Public Utilities Commission of Nevada has approved a $7 million annualized rate increase. The new rates became effective in November. However, the rate hike is much lower than the $27 million increase the company had been seeking. Including other aspects of the decision, Southwest estimates an annual operating income benefit of around $11.4 million. The company also identified several items it may request to have formally reconsidered by the commission. Southwest's focus on this matter is to be expected, as it depends on approved revenue increases to help it cope with higher costs and as compensation for infrastructure investment.

Performance may well continue to improve in 2013. The utility business should benefit from modest customer growth and recently granted rate relief. Meantime, the construction services subsidiary should continue to experience healthy demand, given the need to replace aging infrastructure.

The stock is not without risk. The company will probably incur greater operating expenses as it continues to expand. Moreover, lagging rate relief or unfavorable temperature variations could hurt the performance of the utility business.

This stock is now neutrally ranked for Timeliness. But the shares have some positive characteristics. Namely, Southwest Gas earns good marks for Price Stability and Earnings Predictability. Dividend growth ought to continue, as well, though the yield will probably remain below the industry average. Even so, this stock has decent total return potential for the coming years.

Michael Napoli, CFA *December 7, 2012*

(A) Based on avg. shares outstand. thru. '98, then diluted. Excl. nonrec. gains (losses): '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Next egs. report due late February. (B) Dividends historically paid early March, June, September, December. † Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	75

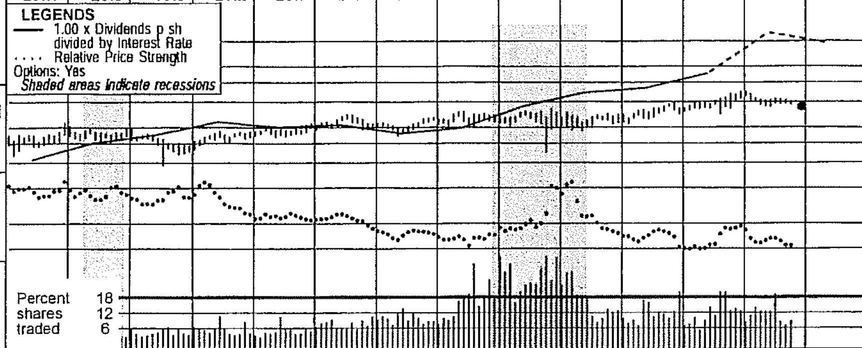
WGL HOLDINGS NYSE-WGL

RECENT PRICE 37.81 | P/E RATIO 14.8 (Trailing: 14.1, Median: 15.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 9/9/11
SAFETY 1 Raised 4/2/93
TECHNICAL 2 Raised 11/2/12
BETA .65 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0					
Low:	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6	31.0	34.7	36.0					

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range
2015 | 2016 | 2017

80
60
50
40
30
25
20
15
10
7.5

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	35	(-5%)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	3	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	88	81	86
to Sell	80	96	83
Hld's(000)	31882	31569	31990

Percent shares traded 18 12 6

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.4	10.8
3 yr.	35.8	48.5
5 yr.	44.8	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.19	24.18	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.98	53.51	52.85	53.98	53.60	53.75	*47.09*	*51.20*	Revenues per sh A	*55.70*
2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	*4.60*	*4.40*	"Cash Flow" per sh	*4.65*
1.85	1.85	1.54	1.47	1.79	1.68	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	2.68	*2.50*	Earnings per sh B	*2.75*
1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	1.59	*1.63*	Div'ds Decl'd per sh C■	*1.75*
2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	*5.85*	*4.85*	Cap'l Spending per sh	*4.80*
12.79	13.48	13.86	14.72	15.31	16.24	15.78	18.25	18.95	17.80	18.86	19.83	20.99	21.89	22.82	23.49	*24.75*	*25.55*	Book Value per sh D	*28.65*
43.70	43.70	43.84	48.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	*51.50*	*51.75*	Common Shs Outst'g E	*52.00*
11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.8	13.7	12.6	15.1	17.0	15.3		Avg Ann'l P/E Ratio	*15.0*
.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.99		Relative P/E Ratio	*1.00*
5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	4.3%		Avg Ann'l Div'd Yield	*4.1%*
						1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	2425.3	*2650*	Revenues ($mill) A	*2895*
						55.7	112.3	98.0	104.8	96.0	102.9	122.9	128.7	115.0	115.5	*138.3*	*130*	Net Profit ($mill)	*145*
						34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
						3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	*5.7%*	*4.9%*	Net Profit Margin	*5.0%*
						45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	*31.0%*	*30.5%*	Long-Term Debt Ratio	*28.5%*
						52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	*67.5%*	*68.0%*	Common Equity Ratio	*70.5%*
						1462.5	1454.9	1443.6	1478.1	1526.1	1825.4	1879.5	1687.7	1774.4	1818.1	1886.9	*1945*	Total Capital ($mill)	*2115*
						1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	2667.4	*2855*	Net Plant ($mill)	*3515*
						5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	8.3%	*7.5%*	Return on Total Cap'l	*7.5%*
						7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	*10.9%*	*10.0%*	Return on Shr. Equity	*9.5%*
						7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	*11.0%*	*10.0%*	Return on Com Equity	*9.5%*
						NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	4.3%	*3.5%*	Retained to Com Eq	*3.5%*
						112%	56%	65%	62%	69%	66%	57%	57%	67%	64%	59%	*65%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $836.9 mill. Due in 5 Yrs $112.0 mill.
LT Debt $589.2 mill. LT Interest $36.4 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x)
Pension Assets-9/12 $1,108.9 mill.
Oblig. $1,417.2 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 51,613,381 shs.
as of 10/31/12

MARKET CAP: $2.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	8.9	4.3	10.3
Other	708.4	720.4	822.5
Current Assets	717.3	724.7	832.8
Accts Payable	225.4	279.4	270.4
Debt Due	130.5	116.5	247.7
Other	188.2	180.8	238.9
Current Liab.	544.1	576.7	757.0
Fix. Chg. Cov.	536%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.5%	2.5%	*.5%*
"Cash Flow"	3.0%	1.5%	*1.5%*
Earnings	3.0%	3.0%	*2.5%*
Dividends	2.0%	2.5%	*2.5%*
Book Value	4.0%	5.0%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	826.2	1040.9	427.0	412.8	2706.9
2010	727.4	1056.6	459.7	465.2	2708.9
2011	795.9	1017.2	490.3	448.1	2751.5
2012	727.8	839.4	438.3	419.8	2425.3
2013	*785*	*895*	*495*	*475*	*2650*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.03	1.65	.11	d.25	2.53
2010	1.01	1.64	d.07	d.29	2.27
2011	1.02	1.53	d.03	d.26	2.25
2012	1.13	1.58	.08	d.10	2.68
2013	*1.08*	*1.54*	*.03*	*d.15*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.34	.36	.36	.36	1.42
2009	.36	.37	.37	.37	1.47
2010	.37	.378	.378	.378	1.50
2011	.378	.39	.39	.39	1.55
2012	.39	.40	.40	.40	

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,082,983 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. Black Rock Inc. owns 7.4% of common stock; Off./dir. less than 1% (1/12 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings posted a mixed bag of financial results for fiscal 2012 (ended September 30th). Revenues declined approximately 12% due to similar downturns at both the utility and nonutility divisions. This largely reflected lower natural gas prices on a year-over-year basis. Nonetheless, this was offset by a tight handle on costs, which helped to reduce operating expenses by 210 basis points as a function of the top line. Consequently, the annual bottom line advanced 19%, to $2.68 for the year, supported by solid contributions at the Regulated Utility, Retail Energy-Marketing, and Commercial Energy Systems units.

However, this year's prospects do not appear to be as bright. Indeed, WGL's management recently released its 2013 earnings guidance of $2.37 to $2.49 per share. This has prompted us to trim a dime off our estimates for this time frame, to $2.50, a move that would represent an annual declined of almost 7%. The bulk of this downturn will likely stem from rising costs for operations & maintenance and employee pension & post retirement benefits. Too, accelerated expenses for pipeline integrity and compliance will also be a detractor this year. And an active capital expenditures pipeline adds to the margin compression. Indeed, WGL has plans for approximately $1.8 billion in growth projects through 2017. However, it is important to note that many of this year's higher costs will be recouped through rate cases down the road, and the diminished bottom line is more of an issue with the timing of expenses, rather than a breakdown in the fundamentals of the company's business. That said, WGL Holdings is expecting to add about 10,500 customer meters this year, and is actively expanding its alternative energy division.

Our Timeliness Ranking System pegs these shares to mirror the broader market averages in the coming six to 12 months. Over that time frame, WGL may appeal to investors with an eye on income generation. In fact, the yield here is above the average of the natural gas utilities group. However, on the downside, capital appreciation potential for the pull to 2015-2017 is limited, due to the stock's steady price action.

Bryan J. Fong — *December 7, 2012*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late Jan. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '11: $594.4 million, $11.56/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

**COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013**

27. Identify which companies or subsidiary companies in the Gas Group are able to use a forecasted test year in base rate proceedings.

Response:

Please refer to the attached spreadsheet.

Group of Gas Distribution Companies

Ticker	Company	Test Year
GAS	AGL Resources, Inc.	
	Florida	fully or partially forecasted
	Georgia	projected
	Illinois	historical or future
	New Jersey	partially projected, fully historical by the time a rate decision is
	Tennessee	forecasted
	Virginia	fully forecasted
ATO	Atmos Energy Corp.	
	Georgia	projected
	Kansas	historical
	Kentucky	historical or forecasted
	Louisiana	historical
	Mississippi	projected
	Tennessee	forecasted
	Texas	historical
LG	Laclede Group, Inc.	
	Missouri	historical or partly forecasted
NJR	New Jersey Resources Corp.	
	New Jersey	partially projected, fully historical by the time a rate decision is
NWN	Northwest Natural Gas	
	Oregon	partially or fully forecasted
	Washington	historical
PNY	Piedmont Natural Gas Co.	
	North Carolina	historical
	South Carolina	historical
	Tennessee	forecasted
SJI	South Jersey Industries, Inc.	
	New Jersey	partially projected, fully historical by the time a rate decision is
SWX	Southwest Gas Corporation	
	Arizona	historical with fair value rate base
	California	fully forecasted
	Nevada	
WGL	WGL Holdings, Inc.	
	District of Columbia	partially-forecasted
	Maryland	partially-forecasted
	Virginia	fully forecasted

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

28. Provide the most current earned ROEs for the Gas Group or their subsidiaries.

Response:

The fiscal year 2012 earned returns are provided below:

Group of Gas Distribution Companies

Ticker	Company	Rate of Return Earned on Book Common Equity
GAS	AGL Resources, Inc.	7.6%
ATO	Atmos Energy Corp.	8.1%
LG	Laclede Group, Inc.	10.5%
NJR	New Jersey Resources Corp.	11.5%
NWN	Northwest Natural Gas	8.2%
PNY	Piedmont Natural Gas Co.	11.8%
SJI	South Jersey Industries, Inc.	13.1%
SWX	Southwest Gas Corporation	10.1%
WGL	WGL Holdings, Inc.	11.2%

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

29. Refer to page 9 of the Moul Testimony.

a. State when Columbia lost three customers due to bypass of its system.

b. Provide an explanation of the bypass threat represented by the eight customers mentioned on lines 19 and 20.

Response:

a. Columbia lost three customers to bypass prior to the beginning of the base test period in this case.

b. The eight customers are in close proximity to interstate pipelines, which present the potential for them to interconnect with those pipelines.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

30. Refer to page 12 of the Moul Testimony.

a. Explain whether the Gas Group companies have mechanisms providing for the recovery of infrastructure investment, similar to Columbia's Accelerated Main Replacement Program mechanism.

b. For each company in the Gas Group, describe the revenue stabilizing regulatory mechanisms referenced on lines 6 through 9.

Response:

Please refer to the table below:

Group of Gas Distribution Companies

Ticker	Company	(a) Infrastructure Investment	(b) revenue stabalization
GAS	AGL Resources, Inc.		
	Florida		
	Georgia	Regulatory infrastructure program rates	Decoupled or straight-fixed-variable rates
	Illinois		
	New Jersey	Regulatory infrastructure program rates	Weather normalization
	Tennessee		Decoupled or straight-fixed-variable rates
	Virginia	Regulatory infrastructure program rates	Weather Normalization/Decoupling–A Weather Normalization Adjustment (WNA) Rider
ATO	Atmos Energy Corp.		
	Georgia	Pipeline Replacement Program (PRP) surcharge	Weather normalization
	Kansas	periodic infrastructure replacement filings	Weather normalization
	Kentucky	Pipeline Replacement Program (PRP) surcharge	Weather normalization
	Louisiana	Rate Stabilization Clause: updated annually without filing a formal rate case	Weather normalization
	Mississippi	Stable Rate Filing: updated annually without filing a formal rate case	Weather normalization
	Tennessee		Weather normalization
	Texas	Texas' Gas Reliability Infrastructure Program (GRIP)	Weather normalization
LG	Laclede Group, Inc.		
	Missouri	Infrastructure System Replacement Surcharge (ISRS) to recover costs associated with certain distribution system replacement projects	
NJR	New Jersey Resources Corp.		
	New Jersey	Accelerated Infrastructure Program (AIP) for 2009, 2010, 2011 and 2012. Safety Acceleration and Facility Enhancement (SAFE) a future four-year Incremental investment program of $130 million.	Full revenue decoupling mechanisms were approved in 2006, suspending the then-existing WNCs. Operation of the mechanism is contingent on the company's achieving certain demand-reduction targets as specified in a BPU-approved conservation incentive program.
NWN	Northwest Natural Gas		
	Oregon	System Integrity Program (SIP) related to the replacement of bare steel, pipeline integrity, and other pipeline safety programs	A decoupling mechanism is in place for NWN that is designed to counteract the impact on revenues of changes in average consumption patterns due to residential and commercial customers' conservation efforts. NWN has a separate weather-adjusted rate mechanism (WARM) in place for residential and commercial customers.
	Washington	pipeline replacement cost recovery mechanism pending	
PNY	Piedmont Natural Gas Co.		
	North Carolina		Margin Decoupling Mechanism/Tracker (MDT), formerly known as the Customer Utilization Tracker, that decouples the recovery of authorized margins from sales levels, thus mitigating the impact of weather and energy conservation programs on revenues.
	South Carolina	Rate stabalization mechanism restates rates annually based on updated costs and revenues	Gas weather normalization adjustments have been in place for several years that apply to residential and small commercial customers during winter months
	Tennessee		Weather normalization
SJI	South Jersey Industries, Inc.		
	New Jersey	Capital Investment Recovery Tracker (CIRT) annua filing to the BPU for review and approval of expenditures recorded	Full revenue decoupling mechanisms were approved in 2006, suspending the then-existing WNCs. Operation of the mechanism is contingent on the company's achieving certain demand-reduction targets as specified in a BPU-approved conservation incentive program.
SWX	Southwest Gas Corporation		
	Arizona	Pipe Replacement Tracking Mechanisms	Full revenue decoupling mechanism with a winterperiod monthly weather adjuster is in place, for most customer classes
	California		Decoupled rate 'structures which mitigate weather risk
	Nevada		Decoupled rate 'structures which mitigate weather risk
WGL	WGL Holdings, Inc.		
	District of Columbia		
	Maryland	S.B. 8 establishes what has been referred to as the Maryland Strategic Infrastructure Development and Enhancement (STRIDE) Program	revenue-normalization mechanism
	Virginia	Infrastructure rider mechanisms	Weather Normalization/Decoupling–A Weather Normalization Adjustment (WNA) Rider

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31. Refer to pages 26 and 27 of the Moul Testimony. Describe the three adjustments to the dividend yield as shown on Attachment PRM-7.

Response:

The electronic copy of the Microsoft Excel spreadsheet provided on CD and labeled Staff Set 2 DR No. 31 Attachment A provides the computation of the ex-dividend date adjustment that is used in calculating the monthly dividend yields. The formulas for the adjustment of the six-month average dividend yield are contained in cells F29, F32, and F35 in Attachment A..

Monthly Dividend Yields for
Delivery Group
for the Twelve Months Ending February 2013

Company	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	12-Month Average	6-Month Average	3-Month Average
AGL RES INC (NYSE:GAS)	4.72%	4.71%	4.92%	4.78%	4.59%	4.65%	4.52%	4.55%	4.73%	4.63%	4.54%	4.71%			
ATMOS ENERGY CORP (NYSE:ATO)	4.41%	4.27%	4.17%	3.95%	3.88%	3.95%	3.87%	3.92%	4.00%	4.00%	3.77%	3.67%			
LACLEDE GROUP INC (NYSE:LG)	4.27%	4.24%	4.40%	4.18%	4.00%	3.97%	3.87%	4.11%	4.22%	4.42%	4.29%	4.21%			
NEW JERSEY RES (NYSE:NJR)	3.42%	3.53%	3.65%	3.49%	3.50%	3.60%	3.50%	3.61%	3.97%	4.05%	3.83%	3.62%			
NORTHWEST NAT GAS CO (NYSE:NWN)	3.95%	3.90%	3.85%	3.76%	3.66%	3.63%	3.64%	3.91%	4.16%	4.15%	4.01%	4.01%			
PIEDMONT NAT GAS INC (NYSE:PNY)	3.87%	3.95%	3.99%	3.73%	3.79%	3.87%	3.70%	3.78%	3.92%	3.84%	3.92%	3.87%			
SOUTH JERSEY INDS INC (NYSE:SJI)	3.22%	3.28%	3.35%	3.17%	3.06%	3.20%	3.05%	3.52%	3.57%	3.53%	3.28%	3.23%			
SOUTHWEST GAS CORPORATION (SWX)	2.49%	2.82%	2.82%	2.71%	2.66%	2.76%	2.68%	2.73%	2.82%	2.79%	2.66%	2.61%			
WGL HLDGS INC (NYSE:WGL)	3.84%	4.00%	4.13%	4.06%	3.97%	4.12%	4.01%	4.03%	4.12%	4.12%	3.83%	3.81%			
Average	3.80%	3.86%	3.92%	3.76%	3.68%	3.75%	3.65%	3.80%	3.95%	3.95%	3.79%	3.75%	3.81%	3.82%	3.83%

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: http://finance.yahoo.com/
http://www.nasdaq.com/symbol/gas/dividend-history

Forward-looking Dividend Yield					
	½ Growth	D_0/P_0	(.5g)	D_1/P_0	$\frac{D_0(1+g)^0+D_0(1+g)^0+D_0(1+g)^1+D_0(1+g)^1}{P_0}$
		3.82%	1.025000	3.91%	
	Discrete	D_0/P_0	Adj.	D_1/P_0	$\frac{D_0(1+g)^{.25}+D_0(1+g)^{.50}+D_0(1+g)^{.75}+D_0(1+g)^{1.00}}{P_0}$
		3.82%	1.031059	3.93%	
	Quarterly	D_0/P_0	Adj.	D_1/P_0	$\left[\left(1+\frac{D_0(1+g)^{.25}}{P_0}\right)^4-1\right]$
		0.9538%	1.012272	3.92%	
	Average			3.92%	
	Growth rate			5.00%	
	K			8.92%	

Month-End Closing Prices

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13
AGL RES INC (NYSE:GAS)	$ 39.220	$ 39.430	$ 37.480	$ 38.750	$ 40.500	$ 39.650	$ 40.910	$ 40.830	$ 38.980	$ 39.970	$ 41.800	$ 39.960
ATMOS ENERGY CORP (NYSE:.	$ 31.460	$ 32.580	$ 33.140	$ 35.070	$ 35.850	$ 34.940	$ 35.790	$ 35.970	$ 35.010	$ 35.120	$ 37.360	$ 38.170
LACLEDE GROUP INC (NYSE:L(	$ 39.020	$ 39.380	$ 38.110	$ 39.810	$ 41.780	$ 42.250	$ 43.000	$ 41.640	$ 40.710	$ 38.610	$ 39.920	$ 40.760
NEW JERSEY RES (NYSE:NJR)	$ 44.570	$ 43.240	$ 41.980	$ 43.610	$ 45.900	$ 44.810	$ 45.720	$ 44.460	$ 40.580	$ 39.620	$ 42.030	$ 44.560
NORTHWEST NAT GAS CO (NY	$ 45.400	$ 45.700	$ 46.350	$ 47.600	$ 48.690	$ 49.170	$ 49.240	$ 46.530	$ 43.860	$ 44.200	$ 45.420	$ 45.550
PIEDMONT NAT GAS INC (NYSE	$ 31.070	$ 30.480	$ 30.320	$ 32.190	$ 31.780	$ 31.230	$ 32.480	$ 31.870	$ 30.860	$ 31.310	$ 31.760	$ 32.240
SOUTH JERSEY INDS INC (NYS	$ 50.040	$ 49.250	$ 48.410	$ 50.970	$ 52.860	$ 50.620	$ 52.930	$ 50.590	$ 49.970	$ 50.330	$ 54.280	$ 55.140
SOUTHWEST GAS CORPORAT	$ 42.740	$ 42.020	$ 41.980	$ 43.650	$ 44.660	$ 42.750	$ 44.200	$ 43.470	$ 41.940	$ 42.410	$ 44.540	$ 45.300
WGL HLDGS INC (NYSE:WGL)	$ 40.700	$ 40.110	$ 38.950	$ 39.750	$ 40.450	$ 39.040	$ 40.250	$ 39.770	$ 39.060	$ 39.190	$ 41.930	$ 42.170

Quarterly Dividend Payment

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13
AGL RES INC (NYSE:GAS)	$ 0.460	$ 0.460	$ 0.460	$ 0.460	$ 0.460	$ 0.460	$ 0.460	$ 0.460	$ 0.460	$ 0.460	$ 0.470	$ 0.470
ATMOS ENERGY CORP (NYSE:.	$ 0.345	$ 0.345	$ 0.345	$ 0.345	$ 0.345	$ 0.345	$ 0.345	$ 0.350	$ 0.350	$ 0.350	$ 0.350	$ 0.350
LACLEDE GROUP INC (NYSE:L(	$ 0.415	$ 0.415	$ 0.415	$ 0.415	$ 0.415	$ 0.415	$ 0.415	$ 0.425	$ 0.425	$ 0.425	$ 0.425	$ 0.425
NEW JERSEY RES (NYSE:NJR)	$ 0.380	$ 0.380	$ 0.380	$ 0.380	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400
NORTHWEST NAT GAS CO (NY	$ 0.445	$ 0.445	$ 0.445	$ 0.445	$ 0.445	$ 0.445	$ 0.445	$ 0.455	$ 0.455	$ 0.455	$ 0.455	$ 0.455
PIEDMONT NAT GAS INC (NYSI	$ 0.300	$ 0.300	$ 0.300	$ 0.300	$ 0.300	$ 0.300	$ 0.300	$ 0.300	$ 0.300	$ 0.300	$ 0.310	$ 0.310
SOUTH JERSEY INDS INC (NYS	$ 0.403	$ 0.403	$ 0.403	$ 0.403	$ 0.403	$ 0.403	$ 0.403	$ 0.443	$ 0.443	$ 0.443	$ 0.443	$ 0.443
SOUTHWEST GAS CORPORAT	$ 0.265	$ 0.295	$ 0.295	$ 0.295	$ 0.295	$ 0.295	$ 0.295	$ 0.295	$ 0.295	$ 0.295	$ 0.295	$ 0.295
WGL HLDGS INC (NYSE:WGL)	$ 0.388	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400	$ 0.400

Ex-Dividend Dates

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13
AGL RES INC (NYSE:GAS)	15-Feb-12	15-Feb-12	16-May-12	16-May-12	16-May-12	15-Aug-12	15-Aug-12	15-Aug-12	14-Nov-12	14-Nov-12	14-Nov-12	13-Feb-13
ATMOS ENERGY CORP (NYSE:	23-Feb-12	23-Feb-12	23-May-12	23-May-12	23-May-12	23-Aug-12	23-Aug-12	23-Aug-12	21-Nov-12	21-Nov-12	21-Nov-12	28-Feb-13
LACLEDE GROUP INC (NYSE:L	08-Mar-12	08-Mar-12	08-Mar-12	07-Jun-12	07-Jun-12	07-Jun-12	07-Sep-12	07-Sep-12	07-Sep-12	07-Dec-12	07-Dec-12	07-Dec-12
NEW JERSEY RES (NYSE:NJR)	13-Mar-12	13-Mar-12	13-Mar-12	13-Jun-12	13-Jun-12	13-Jun-12	20-Sep-12	20-Sep-12	20-Sep-12	12-Dec-12	12-Dec-12	12-Dec-12
NORTHWEST NAT GAS CO (NY	27-Jan-12	26-Apr-12	26-Apr-12	26-Apr-12	27-Jul-12	27-Jul-12	27-Jul-12	29-Oct-12	29-Oct-12	29-Oct-12	29-Jan-13	29-Jan-13
PIEDMONT NAT GAS INC (NYSI	21-Mar-12	21-Mar-12	21-Mar-12	20-Jun-12	20-Jun-12	20-Jun-12	20-Sep-12	20-Sep-12	20-Sep-12	20-Dec-12	20-Dec-12	20-Dec-12
SOUTH JERSEY INDS INC (NYS	07-Mar-12	07-Mar-12	07-Mar-12	07-Jun-12	07-Jun-12	07-Jun-12	06-Sep-12	06-Sep-12	06-Sep-12	06-Dec-12	06-Dec-12	06-Dec-12
SOUTHWEST GAS CORPORAT	13-Feb-12	13-Feb-12	11-May-12	11-May-12	11-May-12	13-Aug-12	13-Aug-12	13-Aug-12	13-Nov-12	13-Nov-12	13-Nov-12	13-Feb-13
WGL HLDGS INC (NYSE:WGL)	06-Jan-12	05-Apr-12	05-Apr-12	05-Apr-12	06-Jul-12	06-Jul-12	06-Jul-12	05-Oct-12	05-Oct-12	05-Oct-12	08-Jan-13	08-Jan-13

Days from Ex-Dividend Date

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13
AGL RES INC (NYSE:GAS)	45	75	15	45	76	16	46	77	16	47	78	15
ATMOS ENERGY CORP (NYSE:	37	67	8	38	69	8	38	69	9	40	71	0
LACLEDE GROUP INC (NYSE:L	23	53	84	23	54	85	23	54	84	24	55	83
NEW JERSEY RES (NYSE:NJR)	18	48	79	17	48	79	10	41	71	19	50	78
NORTHWEST NAT GAS CO (NY	64	4	35	65	4	35	65	2	32	63	2	30
PIEDMONT NAT GAS INC (NYSE	10	40	71	10	41	72	10	41	71	11	42	70
SOUTH JERSEY INDS INC (NYS	24	54	85	23	54	85	24	55	85	25	56	84
SOUTHWEST GAS CORPORATI	47	77	20	50	81	18	48	79	17	48	79	15
WGL HLDGS INC (NYSE:WGL)	85	25	56	86	25	56	86	26	56	87	23	51

Adjusted Prices

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13
AGL RES INC (NYSE:GAS)	$38.993	$39.051	$37.404	$38.523	$40.116	$39.569	$40.677	$40.441	$38.899	$39.732	$41.397	$39.883
ATMOS ENERGY CORP (NYSE:.	$31.320	$32.326	$33.110	$34.926	$35.588	$34.910	$35.646	$35.705	$34.975	$34.966	$37.087	$38.170
LACLEDE GROUP INC (NYSE:L(	$38.915	$39.138	$37.727	$39.705	$41.534	$41.862	$42.895	$41.388	$40.318	$38.498	$39.663	$40.372
NEW JERSEY RES (NYSE:NJR)	$44.495	$43.040	$41.650	$43.539	$45.689	$44.463	$45.676	$44.280	$40.268	$39.536	$41.810	$44.217
NORTHWEST NAT GAS CO (NY	$45.087	$45.680	$46.179	$47.282	$48.670	$48.999	$48.922	$46.520	$43.700	$43.885	$45.410	$45.400
PIEDMONT NAT GAS INC (NYSI	$31.037	$30.348	$30.086	$32.157	$31.645	$30.993	$32.447	$31.735	$30.626	$31.274	$31.617	$32.002
SOUTH JERSEY INDS INC (NYS	$49.934	$49.011	$48.034	$50.868	$52.621	$50.244	$52.824	$50.323	$49.557	$50.208	$54.008	$54.732
SOUTHWEST GAS CORPORAT	$42.603	$41.770	$41.915	$43.488	$44.397	$42.692	$44.044	$43.214	$41.885	$42.254	$44.284	$45.251
WGL HLDGS INC (NYSE:WGL)	$40.338	$40.000	$38.704	$39.372	$40.340	$38.794	$39.872	$39.656	$38.814	$38.808	$41.829	$41.946

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32. Provide the monthly data underlying the dividend yields for the Gas Group shown on PRM-7.

Response:

Please refer to PSC DR Set 2 No. 31 Attachment A, which provides the data underlying the dividend yields for the Gas Group.

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33. Refer to pages 42 and 43 of the Moul Testimony. If recent A-rated utility bond yields have ranged from 3.84 to 4.48 percent, explain why a forecasted 5 percent yield was used to calculate the risk premium.

Response:

The forecasts indicate that interest rates are projected to increase in the future. This is shown by the development of the forecast yields on A-rated public utility bonds provided on page 44 of Mr. Moul's pre-filed direct testimony. This trend toward higher bond yields is also revealed by the average yield of 4.70% for A-rated public utility bonds in July 2013.

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34. Considering the yields to maturity for the first and second quarters of 2013 as shown on pages 1 and 2 of PRM-14, explain how it is reasonable to use 3.5 percent as the risk-free rate in the Risk Premium and Capital Asset Pricing Model analyses.

Response:

These data should be viewed in conjunction with forecast interest rates that are shown on page 2 of Attachment PRM-14. Shown there, a clear trend of higher treasury yields is indicated that provides support for a higher risk-free rate of return of 3.5% for use in the CAPM. Indeed, subsequent actual treasury yields support a 3.5% risk-free rate of return at this time. For example, according to the Federal Reserve statistical release (H.15), the 30-year treasury bond yield was 3.58% for the week ended July 19, 2013.

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35. Explain why the 8.55 percent forecast market premium from PRM-14 was not used in the CAPM cost of equity calculation, consistent with the use of other forecasts employed in the ROE analyses.

Response:

The 8.55% forecast market premium was blended with historical market premium of 8.69%. The average of the historical and forecast market premium was 8.62%. Using the forecast alone, would have changed the CAPM result by just 0.05% (11.10% - 11.05%).

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36. Explain why the Comparable Earnings analysis as shown in PRM-15 is based on companies with Betas of .55 to .75, as opposed to companies having either (a) betas of .65 or (b) companies with betas in a range of .6 to .7. Show Comparable Earnings results under both these scenarios.

Response:

The range of 0.55 to 0.75 was selected because these are the bounds of the betas of the Gas Group (see page 2 of Attachment PRM-3). If the range of the betas was reduced to 0.60 to 0.70, the Comparable Earnings result would have been 12.25% (11.5% + 13.0% = 24.5% ÷ 2). The spreadsheet showing those results is attached. Restricting the betas to just .65 would result in just six (6) companies in the Comparable Earnings group, which would be too small of a sample for this purpose.

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Staff Set 2 DR No. 36
Attachment A
Page 1 of 2
Respondent: P.R. Moul

Comparable Earnings Approach

Using Non-Utility Companies with
Timeliness of 2 & 3; Safety Rank of 1, 2 & 3; Financial Strength of B, B+, B++ & A;
Price Stability of 100; Betas of .55 to .75; and Technical Rank of 2 & 3

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
AmerisourceBergen	MEDICNON	3	2	B++	100	0.70	2
Berkley (W.R.)	INSPRPTY	2	2	B++	95	0.70	2
Capitol Fed. Fin'l	THRIFT	3	3	B+	95	0.65	3
Church & Dwight	HOUSEPRD	2	1	A	100	0.60	3
Clorox Co.	HOUSEPRD	2	2	B++	100	0.60	3
DaVita Inc.	MEDSERV	2	3	B+	95	0.70	3
Dollar General	RETAIL	2	3	B++	95	0.60	3
Haemonetics Corp.	MEDICNON	3	2	B++	95	0.65	3
Hershey Co.	FOODPROC	2	2	B++	100	0.65	2
Hormel Foods	FOODPROC	3	1	A	100	0.65	3
Kroger Co.	GROCERY	3	2	B++	95	0.60	3
Laboratory Corp.	MEDSERV	3	1	A	100	0.65	3
People's United Fin'l	THRIFT	3	3	B+	95	0.70	3
Stericycle Inc.	ENVIRONM	2	2	B++	95	0.70	3
Verisk Analytics	INFOSER	2	2	B+	100	0.60	3
Waste Connections	ENVIRONM	3	3	B+	95	0.70	2
Weis Markets	GROCERY	3	1	A	95	0.65	3
Average		3	2	B++	97	0.65	3
Gas Group	Average	3	2	B++	100	0.66	3

Source of Information: Value Line Investment Survey for Windows, January 2013

PSC Case No. 2013-00167
Staff Set 2 DR No. 36
Attachment A
Page 2 of 2
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Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2007-2011 and
Projected 3-5 Year Returns

Company	2007	2008	2009	2010	2011	Average	Projected 2015-17
AmerisourceBergen	15.9%	17.3%	18.8%	21.6%	24.6%	19.6%	27.5%
Berkley (W.R.)	20.6%	16.5%	10.2%	11.4%	7.7%	13.3%	12.5%
Capitol Fed. Fin'l	3.7%	5.8%	7.0%	7.1%	3.3%	5.4%	4.5%
Church & Dwight	15.6%	15.1%	15.5%	15.3%	15.9%	15.5%	17.0%
Clorox Co.	NMF	-	-	NMF	NMF	-	NMF
DaVita Inc.	19.7%	19.2%	19.8%	22.8%	22.5%	20.8%	19.0%
Dollar General	-	3.8%	10.0%	15.5%	16.4%	11.4%	19.0%
Haemonetics Corp.	11.4%	11.9%	12.5%	12.2%	10.7%	11.7%	12.0%
Hershey Co.	81.3%	135.3%	69.3%	65.1%	76.4%	85.5%	52.5%
Hormel Foods	15.8%	14.2%	16.1%	17.0%	17.8%	16.2%	16.0%
Kroger Co.	24.0%	24.1%	23.2%	21.1%	30.0%	24.5%	23.5%
Laboratory Corp.	29.4%	30.4%	25.3%	23.7%	25.8%	26.9%	20.0%
People's United Fin'l	3.4%	2.7%	2.0%	1.6%	3.8%	2.7%	6.0%
Stericycle Inc.	18.0%	22.8%	21.1%	20.4%	20.2%	20.5%	15.0%
Verisk Analytics	-	-	-	-	-	-	37.0%
Waste Connections	12.8%	8.2%	8.7%	10.5%	12.1%	10.5%	13.5%
Weis Markets	7.1%	7.1%	9.1%	9.4%	10.1%	8.6%	9.0%
Average						19.5%	19.0%
Average (excluding values >20%)						11.5%	13.0%

**COLUMBIA GAS OF KENTUCKY, INC.
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37. Provide an electronic copy of the excel spreadsheets supporting the Moul Testimony and the responses to the items in this request for information, where appropriate, with the underlying data and formulas intact.

Response:

Included on a separate CD are the individual Microsoft Excel spreadsheets for each of the attachments that go with Mr. Moul's testimony. All underlying data is provided in tabs that follow each schedule. Further, all formulas are intact.

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38. In Case No. 2009-00141,[2] Columbia filed two cost of service studies, a Demand-Commodity Study and a Customer-Demand Study. In the instant case, Columbia filed two cost of service studies, a Design Day Study and a Peak and Average Study. Explain the differences between the cost of service studies filed in Case No. 2009-00141 and the ones filed in this case and why the change was made in the type of cost of service studies filed.

Response:

In Columbia's current proceeding, the two cost of service studies that were filed are conceptually very similar to the two cost of service studies previously filed in Case No. 2009-00141. In both proceedings, Columbia sought to provide a range of results for evaluating class revenues and rate design among its rate classes by utilizing two different demand cost allocation methodologies: (1) a coincident peak day demand allocation method; and (2) a peak and average demand

[2] Case No. 2009-00141, Application of Columbia Gas of Kentucky, Inc. for an Adjustment in Rates (Ky. PSC Oct. 26, 2009).

allocation method. The parallel alignment of the cost of service studies filed in both proceedings, from a demand cost allocation perspective, is presented below.

Demand Allocation Method	**Case No. 2009-00141**	**Case No. 2013-00167**
Coincident Peak Day	Customer-Demand Study	Design Day Study
Peak and Average	Demand-Commodity Study	Peak and Average Study

In both the "Peak and Average Study" and "Demand-Commodity Study," a 50/50 weighting between demand and commodity was used to derive the composite cost classification and allocation factors.

Although both sets of cost studies are conceptually very similar, there are certain differences that pertain to the manner in which specific plant or expense accounts are allocated to Columbia's rate classes or how certain cost allocation factors are derived. For example, in Columbia's currently filed Design Day Study, distribution mains were classified and allocated using a zero-intercept methodology while in its Customer-Demand Study filed in Case No. 2009-00141, Columbia utilized a minimum system methodology for classifying and allocating distribution mains plant and associated expenses to its rate classes. In addition, in Columbia's currently-filed cost of service studies, there was greater reliance on the use of special studies, composite allocation factors, and internally-generated cost allocation factors to assign certain plant and expense items (e.g., Customer

Accounts Expenses, Administrative & General Expenses) compared to the cost studies filed in Case No. 2009-00141.

The reason these types of changes were made to Columbia's cost of service studies in this proceeding was because of the availability of more detailed plant and expense data, the use of a cost of service study computer model which enabled the creation of composite allocation factors, and an interest in making methodological enhancements to Columbia's previous cost classification and allocation processes, where appropriate.

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39. Refer to Volume 9 of the application, the Direct Testimony of Russell A. Feingold ("Feingold Testimony"). On page 39, beginning at line 6, Mr. Feingold states that Columbia's rate classes "received increases in revenues generally in proportion to their cost-based revenue requirements at proposed revenue levels... adjusted for a maximum increase in non-gas base revenues to any one rate class of approximately 1.14 times the overall increase in Columbia's non-gas base revenues."

a. Provide the calculations described above for each rate class receiving a proposed increase.

b. Explain the basis for the 1.14 used in the maximum increase calculation.

Response:

a. Please refer to the Attachment provided in Columbia's response to AG data request number 1-264.

b. Columbia's apportionment of the proposed revenue increase among its rate classes was based upon deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates, including: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. The process followed by Columbia is explained at pages 36-40 of Mr. Feingold's prepared direct testimony. The 1.14 factor was derived as a result of this process, and reflects the maximum increase in non-gas base revenues to any one rate class as a function of the overall increase in Columbia's non-gas base revenues. The computational impact of utilizing this factor is presented in the Attachment provided in Columbia's response to AG data request number 1-264 under the tab entitled, "Class Revenue Worksheet." The application of this factor as part of the class revenue increase process limited the proposed increase to Columbia's GS-RES and IUS rate classes in recognition of the above-described criteria. This factor reflects the various judgmental considerations made by Columbia for each of its rate classes which created the desirable ratemaking results described at page 39, lines 11-19, of Mr. Feingold's prepared direct testimony.

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40. Refer to page 42 of the Feingold Testimony.

a. This page provides a discussion of Columbia's current rate design working against the goal of ensuring that it is provided a reasonable opportunity to recover its cost, including return on investment. State whether Columbia's Gas Cost Adjustment Clause, Weather Normalization Adjustment, Energy Efficiency and Conservation Rider, and Accelerated Main Replacement Program Rider are considered to be part of Columbia's rate design.

b. Considering the revenue-stabilizing effects of the Commission-approved mechanisms above, state whether the addition of a Revenue Normalization Adjustment ("RNA") Rider as proposed by Columbia moves beyond providing a reasonable opportunity and toward a guarantee of return on investment.

c. Provide the annual impact on Columbia's cost and revenue since 2009 of adding new customers as discussed at the bottom of page 42 of the Feingold Testimony.

d. Provide Columbia's net customer additions since 2009 for each rate class.

Response:

a. The reference to "Columbia's current rate design" refers directly to the specific structure of its gas distribution service rates and, in particular, to the attempt to recovery of fixed costs through volumetric charges without the ability to recognize changes in customers' usage levels from those used to set base rates. The parts of Columbia's rate design listed in the question are additional tariff provisions which recover costs that are part of Columbia's overall cost of service. Certain of these costs are in addition to Columbia's cost of gas distribution service and are designed to recover specific costs such as the cost of purchased gas. Columbia's Gas Cost Adjustment clause contains a true-up or reconciliation provision that assures that revenues match actual costs. Columbia's Weather Normalization Adjustment is a partial decoupling measure recognizing that the volumetric recovery of fixed gas distribution costs produces outcomes that are not just and reasonable for both customers (during colder than normal weather) and for Columbia (during warmer than normal weather). While each of these tariff provisions addresses a specific issue related to recovery of costs associated with the utility services provided by Columbia, they do not address the fundamental concern of using volumetric rates to recover fixed costs when customers' gas usage is declining. This type of rate design has become unreasonable over time because of fundamental changes in the energy marketplace and no longer results in just and reasonable rates for gas distribution service absent an additional tariff provision to reflect the under recovery of fixed costs when gas use per customer declines. It is a fundamental provision of regulation that a utility's approved rates provide for a reasonable opportunity to earn its allowed rate of return. Without such tariff provision to reflect this type of under recovery, there is no justification for continuing the volumetric recovery of fixed costs.

b. Mr. Feingold does not agree with the outcome portrayed in the question. The evidence in this case shows that despite the ratemaking mechanisms already approved by the Commission and Columbia management's ongoing cost controls, it has been unable to earn the allowed rate of return any time in recent history. It is evident that Columbia's current combination of tariff provisions is inadequate given the nature of the current energy marketplace and its current non-gas, base rates that attempt to recover fixed costs through volumetric charges. Without Columbia's proposed RNA mechanism as an additional means to match its non-gas revenues with costs, Columbia has no reasonable opportunity to earn its allowed rate of return.

c. The table below shows Columbia's estimated annual cost and revenue impact due to adding new customers since 2009. Note that the total revenue includes all surcharges. CHOICE marketer gas cost revenue is excluded.

	2009	2010	2011	2012
Residential				
Gross Customer Additions	192	215	214	354
Total Annual Bill per Customer	$ 785	$ 604	$ 648	$ 523
Estimated Revenue Impact	$ 150,657	$ 129,768	$ 138,726	$ 185,269
Commercial				
Gross Customer Additions	108	91	84	113
Total Annual Bill per Customer	$ 3,716	$ 2,560	$ 2,604	$ 2,010

Estimated Revenue Impact	$ 401,380	$ 232,938	$ 218,743	$ 227,078
Total Revenue	$ 552,036	$ 362,706	$ 357,468	$ 412,347
Growth CapEx / Customer	$ 5,993	$ 4,160	$ 5,174	$ 5,884
Total Cost	1,798,000	1,273,000	1,542,000	2,748,000

d. The table below shows net customer additions since 2009.

Residential	2009	2010	2011	2012
Customer Additions	192	215	214	354
Customer Attrition	(1,863)	(488)	(1,313)	(589)
Net Customer Additions	(1,671)	(273)	(1,099)	(235)
Commercial				
Customer Additions	108	91	84	113
Customer Attrition	(345)	(139)	(158)	(148)
Net Customer Additions	(237)	(48)	(74)	(35)

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41. Refer to page 45 of the Feingold Testimony. Provide any documentation available supporting the statement based on general industry experience that 55 to 60 percent of non-gas base revenue recovery through volumetric charges is above average for gas distribution utilities.

Response:

In the normal course of Mr. Feingold's consulting activities with gas distribution utilities, he does not maintain in his files the specific documentation that would enable him to computationally support his statement made at page 45, lines 12-14, of his prepared direct testimony. Mr. Feingold's general industry experience over his 35 year consulting career that informed his view on this issue consists of the numerous utility costing and ratemaking projects with gas distribution utilities during which time he has analyzed the manner in which these utilities recover non-gas base revenues through their rate structures, the level of their customer and volumetric delivery charges, and the industry-wide utility ratemaking and regulatory trends that have occurred over time.

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42. Refer to the Feingold Testimony, footnote 3 on page 51 and footnote 5 on page 74. State whether Columbia has considered proposing a modification to its WNA clause to address weather variability occurring during months with Heating Degree Days that are excluded by its WNA mechanism.

Response:

The Company originally proposed a WNA that covered the heating season months, billing December through April and has not considered proposing a modification to the WNA clause.

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43. State whether it is reasonable to expect average residential usage to continue to decline at the rate experienced by Columbia over the last five to 10 years as discussed on page 51 of the Feingold Testimony.

Response:

Columbia witness Feingold cited these factors that affect residential usage - "increased efficiency of gas appliances (especially space heating equipment), reduced appliance saturation in homes with natural gas, and tighter, more energy efficient homes." These factors are still in place causing residential usage to decline.

While it is possible that the average residential usage will decline at the rate experienced over the last ten years, Columbia does not expect this rate of decline because it does not expect significant price increases such as occurred in the first half of the period in question. While Columbia does think it is reasonable to expect average residential usage to continue to decline at the rate experienced over the last five years, the forecasted test year in this filing has a lower rate of decline than observed in those years.

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44. State whether the average annual use per customer referenced on page 51 of the Feingold Testimony and as shown on Attachment RAF-4 is weather-adjusted use per customer.

Response:

The referenced data is weather-adjusted use per customer.

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45. Refer to page 54 of the Feingold Testimony, which discusses the reliance on the ratemaking principle of gradualism by the Commission as well as other stakeholders. State when the Commission last took any action with regard to increases in Columbia's monthly customer charges other than to approve settlements to which Columbia was a signatory.

Response:

Monthly customer charges of Columbia have been increased only in settlements approved by the Commission and to which Columbia was a signatory. The last increase having been authorized in Case No. 2009-00141. Columbia notes that the Commission's Order in Case No. 2008-00408, dated October 6, 2011, discussed the increases in the residential customer charges granted to the major LDCs in Kentucky, including Columbia. The Commission's discussion compared the customer charges in effect in March 2011 to those that were in effect in March 2007 and stated, "Given its consideration of the principle of gradualism, it is unlikely that the Commission would have authorized rates that were fully cost-based at the time of its decisions in the cases cited above." (In the Matter of Consideration of the new Federal Standards of the Energy Independence and Security Act of 2007, Case No. 2008-00428, Order dated October 6, 2011, page 95.)

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46. Refer to page 57 and page 75, lines 7 through 13 of the Feingold Testimony. State whether residential customers are the only customers served by Columbia that undertake energy-conservation and efficiency measures.

Response:

All gas customers undertake economic conservation and efficiency measures to varying degrees. However, the results of these measures may not be the same across a utility's various rate classes. In some cases, gas use may still increase. In other cases, the distribution revenue impact on the utility may be small based on greater fixed cost recovery through fixed monthly charges.

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47. Refer to page 58, lines 1 and 2 of the Feingold Testimony. Provide details of other RNA mechanisms similar to that proposed by Columbia. The information provided should include at a minimum the jurisdictions and proceedings in which they were approved, the customer classes subject to the mechanism, and the details of the tariffs setting out the mechanisms' parameters.

Response:

Mr. Feingold does not maintain in his files each of the specific details of revenue decoupling mechanisms approved by utility regulators that are requested in this data request. The attachment hereto presents the information on revenue decoupling mechanisms that Mr. Feingold does have in his possession that he has compiled over time as a general reference source for his utility consulting activities related to this topic.

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Case/Docket	Type	Applies to All Classes
Arkansas Oklahoma Gas	AR	2007	Docket 06-161-U	Full w/WNA	No
Arkansas Western Gas	AR	2007	Docket 06-124-U	Full w/WNA	No
CenterPoint Energy	AR	2007	Docket 07-126-U	Full w/WNA	No
Southwest Gas	AZ	2012	D-G-01151A-10-0458	Full	No
Pacific Gas and Electric	CA	2002	Application No. 02-02-012	Full	Yes
San Diego Gas and Electric	CA	2002	Application No. 02-02-012	Full	Yes
Southern California Gas	CA	2002	Application No. 02-02-012	Full	Yes
Southwest Gas	CA	2002	Application No. 02-02-012	Full	Yes
North Shore Gas Company	IL	2008	Docket No. 07-0242	Full	No
Peoples Gas Light and Coke Company	IL	2008	Docket No. 07-0241	Full	No
Citizens Energy Group	IN	2007	Cause No. 42767	Full	No
Vectren Indiana Gas	IN	2006	Cause No. 43046	Full w/WNA	No
Vectren Southern Indiana G&E	IN	2006	Cause No. 42493	Full w/WNA	No

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Case/Docket	Type	Applies to All Classes
Boston Gas and Colonial Gas	MA	2010	DPU 10-55	Full	No
Columbia Gas of Massachusetts (Bay State Gas)	MA	2009	DPU 09-30	Full	No
Fitchburg Gas and Electric	MA	2011	DPU 11-01 and 11-02	Full	Yes
New England Gas	MA	2010	DPU 10-114	Full	No
Baltimore Gas and Electric	MD	1998	Case No. 8780	Full	No
Washington Gas Light	MD	2005	Case No. 8990	Full	No
Integrys Michigan Gas Utilities	MI	2010	C-U-15990	Full w/WNA	No
DTE Energy (Michigan Consolidated Gas)	MI	2010	C-U-15985	Full w/WNA	No
CenterPoint Minnesota Gas	MN	2008	D-G-008/GR-08-1075	Partial	No
Minnesota Energy Resources	MN	2012	D-G-007,011/GR-10-977	Full	No
Piedmont Natural Gas	NC	2005	G-9, Sub 499, 461, G-44, Sub 15	Full	No
Public Service Co. of North Carolina	NC	2008	G-5, Sub 495	Full	No
New Jersey Natural Gas	NJ	2006	Docket No. GR05121020	Full	No

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Case/Docket	Type	Applies to All Classes
South Jersey Gas	NJ	2006	Docket No. GR05121020	Full	No
Southwest Gas	NV	2009	D-09-04003	Full	No
Central Hudson Gas & Electric	NY	2009	Case No.	Full w/WNA	No
Consolidated Edison of New York	NY	2007	Case No. 06-G-1332	Full w/WNA	No
Corning Gas	NY	2009	Case No. 08-G-1137	Full w/WNA	No
National Fuel Gas Distribution	NY	2007	Case No. 07-G-0141	Full w/WNA	No
National Grid Long Island (Keyspan Gas)	NY	2009	Case No. 06-G-1185/1186	Full w/WNA	No
National Grid New York (Brooklyn Union Gas)	NY	2009	Case No. 06-G-1185/1186	Full w/WNA	No
National Grid Niagara Mohawk	NY	2009	Case No. 08-G-0609	Full w/WNA	No
New York State Electric & Gas Corporation	NY	2010	Case No. 09-G-0715	Full w/WNA	No
Orange and Rockland Utilities	NY	2009	Case No. 08-G-1398	Full w/WNA	No
Rochester Gas and Electric	NY	2009	Case No. 09-G-0717	Full w/WNA	No
St. Lawrence Gas	NY	2009	Case No. 08-G-1392	Full w/WNA	No

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Case/Docket	Type	Applies to All Classes
Cascade Natural Gas	OR	2006	Docket UG-167	Full	No
Northwest Natural Gas	OR	2002	Docket UG-143	Full w/WNA	No
National Grid Narragansett	RI	2012	Docket No. 4206	Full w/WNA	No
Chattanooga Gas	TN	2010	D-09-00183	Full w/WNA	No
Questar Gas Company	UT	2006	Docket No. 05-057-T01	Full w/WNA	No
Columbia Gas of Virginia	VA	2009	PUE-2009-00051	Full w/WNA	No
Virginia Natural Gas	VA	2006	PUE-2008-00064	Full w/WNA	No
Washington Gas Light	VA	2010	PUE-2009-00064	Full w/WNA	No
Avista Corp.	WA	2006	Docket No. UG-060518	Partial	No
Cascade Natural Gas	WA	2006	Docket No. UG-060256	Partial	No
Wisconsin Public Service	WI	2008	Docket No. 6690-UR-119	Full	No
Questar Gas Company	WY	2009	Docket No. 30010-94-GR-08	Full w/WNA	No
SourceGas	WY	2011	D-30022-148-GR-10	Full w/WNA	No

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48. Refer to page 62 of the Feingold Testimony. State whether the 21 states with revenue decoupling include only residential customers in their revenue decoupling mechanisms.

Response:

Revenue decoupling can apply to customers other than residential customers, although the revenue impacts are typically concentrated in the residential class. The approved revenue decoupling mechanisms in the U.S. do include other rate classes besides the residential class.

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49. Explain why Columbia is not proposing to include variations in weather in its RNA as a substitute for the WNA mechanism.

Response:

Columbia's current WNA Clause is more efficient and timely in recovering the weather-related impacts on non-gas base revenues since it is a real-time ratemaking mechanism. This makes it preferable for both customers and Columbia compared to the lagged manner in which such impacts would be accommodated in Columbia's proposed RNA mechanism.

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50. Refer to the explanation of the application of Columbia's proposed RNA to only residential customers on page 75, lines 7 through 13, of the Feingold Testimony.

a. Explain whether Columbia has experienced a decline in average usage per customer in any other rate class.

b. State what percent of Columbia's non-gas base revenues is represented by residential volumetric delivery charge revenue at both current and proposed rates and rate design.

Response:

a. Columbia monitors the residential and commercial classes. The commercial class contains a wide variety of customers including small retail establishments, hospitals and universities. The average usage in this class does not have the compelling downward trend observed in the residential class.

b. Columbia's non-gas base revenue designed to be recovered from its residential volumetric delivery charge is 28% of Columbia's total non-gas base revenue at both current and proposed rates and rate design.

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51. Refer to page 77, lines 12 through 14, of the Feingold Testimony. Explain how normalized gas volumes would be estimated under Columbia's proposed methodology.

Response:

The volumes would be based on the forecasted volumes which are normal by definition.

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52. Refer to page 87 of the Feingold Testimony, lines 6 through 15. Considering the earlier discussion of the importance of recovering fixed costs through the fixed monthly customer charge, explain why Columbia is not proposing to increase the customer charge of the IS and DS/IS rate schedules by the small amount necessary to reach the level indicated by the cost of service studies

Response:

Besides the rationale presented by Mr. Feingold at page 87 of his prepared direct testimony, another reason for maintaining the current customer charge in Columbia's IS and DS/IS rate schedules was because the additional amount of non-gas base revenue that could be recovered through these monthly charges represents only about $15,000 compared to the current non-gas base revenue for these rate schedules of about $4.3 million, or 0.35 percent.

COLUMBIA GAS OF KENTUCKY, INC.
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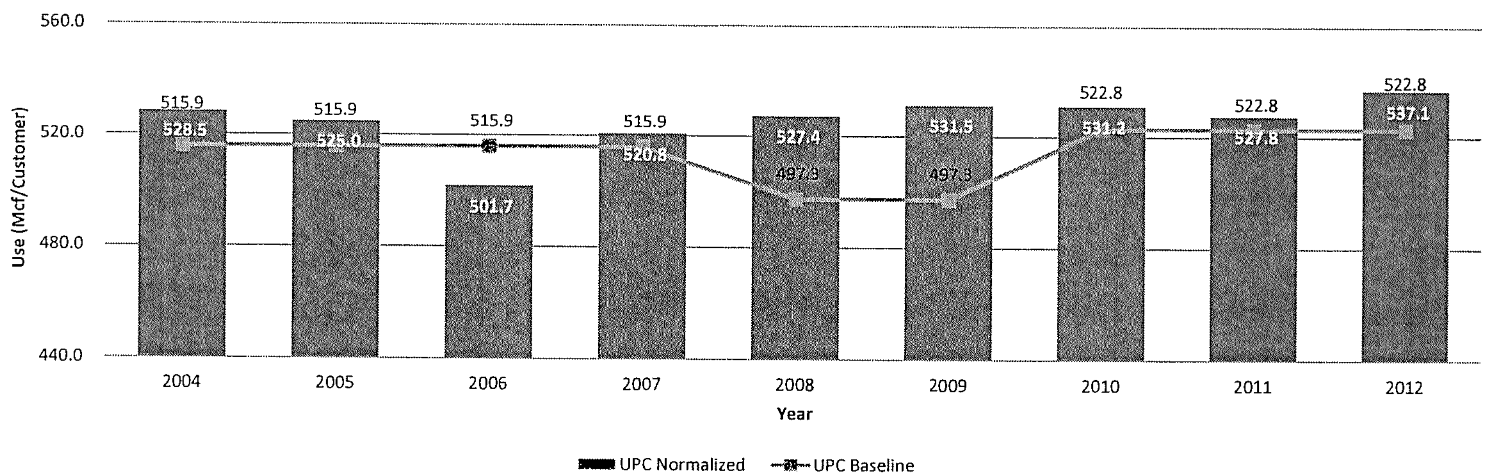
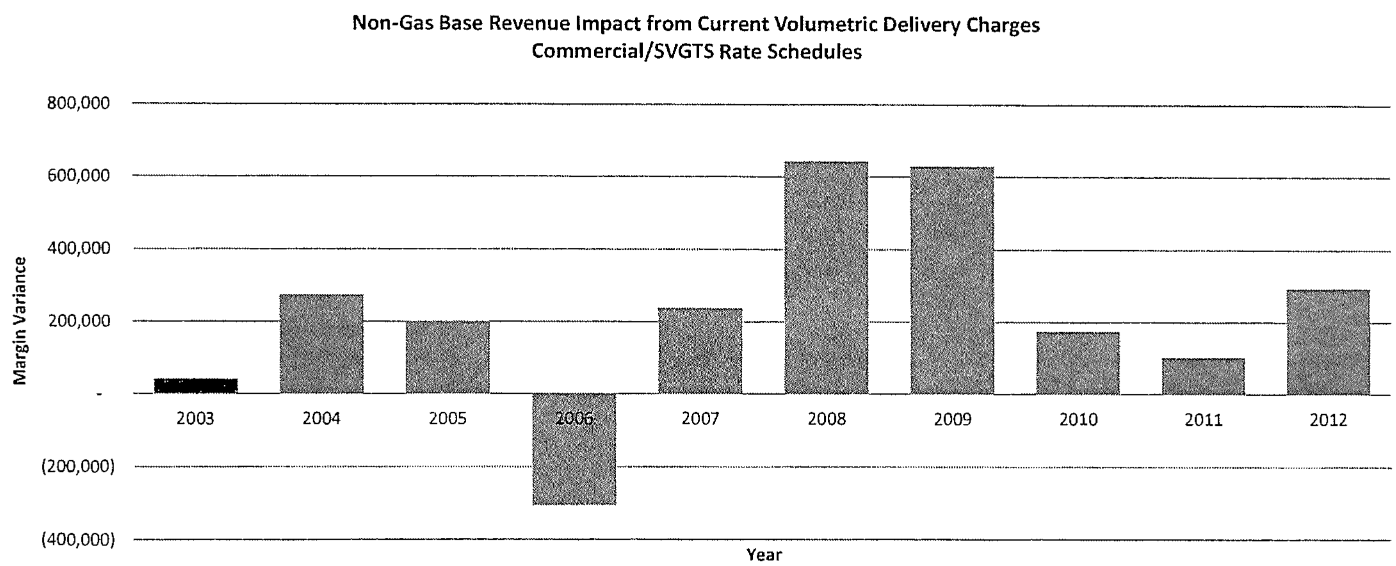
53. Attachments RAF-4 and RAF-5 show Average Annual Use per Customer for the period 2003 through 2012 and Non-Gas Base Revenue Impact from Current Volumetric Delivery Charges for the same period for rate schedules GSR and SVGTS. Provide the same information in identical format for all other rate classes.

Response:

Please see Attachment A of this response.

Average Annual Use per Customer
Commercial/SVGTS Rate Schedules




Non-Gas Base Revenue Impact from Current Volumetric Delivery Charges
Commercial/SVGTS Rate Schedules
800,000
600,000
400,000
200,000
-
(200,000)
(400,000)
Margin Variance
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year

Columbia Gas of Kentucky, Inc.
Non-Gas Base Revenue Impact from Current Volumetric Delivery Charges - Commercial/SVGTS Rate Schedules
For Years 2003 - 2012

	Jan-Feb 2003	Mar-Dec 2003	2004	2005	2006	Jan-Aug 2007	Sep-Dec 2007	2008	Jan-Oct 2009	Nov-Dec 2009	2010	2011	2012
Year End Customers	14,678	14,678	14,750	14,747	14,541	14,452	14,452	14,361	14,124	14,124	14,077	14,002	13,968
UPC Baseline	N/A	515.9	515.9	515.9	515.9	515.9	497.3	497.3	497.3	522.8	522.8	522.8	522.8
UPC Normalized	518.2	518.2	528.5	525.0	501.7	520.8	520.8	527.4	531.5	531.5	531.2	527.8	537.1
Increase / (Decrease) UPC	N/A	2.30	12.60	9.10	(14.20)	4.90	23.50	30.10	34.20	8.70	8.40	5.00	14.30
Rate / Mcf	N/A	1.4816	1.4816	1.4816	1.4816	1.4816	1.4904	1.4904	1.4904	1.4747	1.4747	1.4747	1.4747
Increase / (Decrease)	N/A	41,682	275,355	198,827	(305,924)	69,946	168,724	644,249	599,937	30,202	174,379	103,244	294,560

Increase / (Decrease) Summary By Year

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Increase / (Decrease)	41,682	275,355	198,827	(305,924)	238,670	644,249	630,138	174,379	103,244	294,560

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54. Provide the non-temperature sensitive usage per customer and the average annual number of customers for the period 2003 through 2012 for the GSR and SVGTS classes.

Response:

Please refer to the table below (note that "SVGTS" is shown as "GTR").

	Average Annual Customers		Base Load Annual Usage	
	GSR	GTR	GSR	GTR
2003	85,652	40,676	14.7	16.1
2004	87,453	38,581	14.8	16.0
2005	92,501	32,824	13.1	14.4
2006	97,395	26,713	12.5	13.2
2007	98,792	25,231	13.0	13.3
2008	97,227	25,759	12.7	13.0
2009	91,634	29,605	9.4	10.2
2010	92,087	28,504	11.2	12.1
2011	91,905	28,157	12.0	12.7
2012	92,640	26,873	11.7	12.4

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55. Provide the actual average annual use per customer for the GSR and SVGTS classes for the 12 months ended April 30, 2013.

Response:

Actual residential average annual usage (Mcf) is shown below for for the 12 months ended April 30, 2013.

Line No.	Month	GSR	SVGTS GTR
1	May-12	2.4	2.7
2	Jun	1.2	1.3
3	Jul	1.0	1.0
4	Aug	0.9	1.0
5	Sep	1.0	1.0
6	Oct	1.8	2.0
7	Nov	5.3	6.0
8	Dec	8.9	9.9
9	Jan-13	13.5	14.8
10	Feb	13.4	14.5
11	Mar	12.5	13.4
12	Apr	8.8	9.6
13	Total	70.7	77.2

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56. Refer to Attachment RAF-7. Provide the calculation of the amounts shown in Line Nos. 1, 8, and 9 columns 2 through 5, the Authorized Quarterly Non-Gas Revenue ("AQNR"), and the Estimated Normalized Gas Volumes for the GSR and SVGTS GSR rate schedules.

Response:

Please refer to the attachment hereto. The amounts shown on Line No. 1 (under columns 2-5), the Authorized Quarterly Non-Gas Revenue ("AQNR") are calculated in Page 7 of this response (using input data from Page 1 and page 6). The "Base Monthly Revenue" amounts are calculated using input data from Pages 2 through 5. The amounts shown on Line Nos. 8 and 9 (under columns 2-5), the Estimated Normalized Gas Volumes are provided in Page 9.

Columbia Gas of Kentucky, Inc.
Actual Bills By Rate Schedule
For Calendar Year 2010, 2011 and 2012

2012

Residential Sales

	GSR	Total
Jan	93,598	93,598
Feb	93,719	93,719
Mar	93,600	93,600
Apr	92,888	92,888
May	92,360	92,360
Jun	91,839	91,839
Jul	91,465	91,465
Aug	91,282	91,282
Sep	91,365	91,365
Oct	92,097	92,097
Nov	93,195	93,195
Dec	94,276	94,276
	1,111,684	1,111,684

Residential Choice

	GTR	Total
Jan	27,625	27,625
Feb	27,508	27,508
Mar	27,487	27,487
Apr	27,285	27,285
May	27,156	27,156
Jun	27,040	27,040
Jul	26,728	26,728
Aug	26,568	26,568
Sep	26,393	26,393
Oct	26,233	26,233
Nov	26,313	26,313
Dec	26,138	26,138
	322,474	322,474

Columbia Gas of Kentucky, Inc.
Case No. 2009 - 00141
Residential Sales and Choice Billing Determinants
For the 12 months ending 12/31/08

Residential Sales Bills

	GSR	New Constr.	Conversion	Attrition	2008 Finaled Bills	Total
Jan	100,900	0	0	(795)	1,665	101,770
Feb	100,102	27	4	(795)	1,802	101,140
Mar	99,785	24	6	(795)	2,315	101,335
Apr	98,695	51	3	(795)	2,362	100,316
May	97,680	84	0	(795)	2,678	99,647
Jun	96,381	60	5	(795)	2,715	98,366
Jul	95,780	162	6	(795)	2,556	97,709
Aug	95,105	175	14	(795)	2,572	97,071
Sep	94,848	208	8	(795)	1,937	96,206
Oct	95,086	207	99	(795)	1,909	96,506
Nov	95,924	370	80	(795)	1,811	97,390
Dec	96,436	418	44	(789)	1,567	97,676
	1,166,721	1,786	269	(9,534)	25,889	1,185,131

Residential Sales Volumes

	GSR	New Constr.	Conversion	Attrition	Total
Jan	1,420,401.5	3,992.0	577.0	(4,719.0)	1,420,251.5
Feb	1,376,211.2	3,472.0	470.0	(4,719.0)	1,375,434.2
Mar	1,108,110.3	2,597.0	341.0	(4,719.0)	1,106,329.3
Apr	695,317.5	1,545.0	202.0	(4,719.0)	692,345.5
May	279,841.5	575.0	82.0	(4,719.0)	275,779.5
Jun	146,474.6	275.0	43.0	(4,719.0)	142,073.6
Jul	106,030.7	180.0	29.0	(4,719.0)	101,520.7
Aug	100,292.5	137.0	25.0	(4,719.0)	95,735.5
Sep	98,189.4	111.0	24.0	(4,719.0)	93,605.4
Oct	147,160.9	130.0	26.0	(4,719.0)	142,597.9
Nov	420,511.4	248.0	36.0	(4,719.0)	416,076.4
Dec	968,444.9	194.0	20.0	(4,716.0)	963,942.9
	6,866,986.4	13,456.0	1,875.0	(56,625.0)	6,825,692.4

Residential Choice Bills

	GTR	2008 Finaled Bills	Total
Jan	24,482	110	24,592
Feb	25,406	104	25,510
Mar	25,514	144	25,658
Apr	25,660	159	25,819
May	25,517	136	25,653
Jun	25,817	204	26,021
Jul	25,643	172	25,815
Aug	25,768	183	25,951
Sep	25,756	199	25,955
Oct	25,906	171	26,077
Nov	26,394	133	26,527
Dec	27,246	141	27,387
	309,109	1,856	310,965

Residential Choice Volumes

	GTR	Total
Jan	386,093.6	386,093.6
Feb	389,019.8	389,019.8
Mar	315,568.4	315,568.4
Apr	206,889.9	206,889.9
May	83,451.6	83,451.6
Jun	42,706.9	42,706.9
Jul	29,918.8	29,918.8
Aug	26,763.2	26,763.2
Sep	28,251.8	28,251.8
Oct	42,635.0	42,635.0
Nov	133,478.3	133,478.3
Dec	310,742.9	310,742.9
	1,995,520.2	1,995,520.2

Columbia Gas of Kentucky Inc.
Revenue @ Current Rates Based on Weather Normalized Volumes
For the 12 Months Ending December 31, 2008

Line No.	Description	Bills (1)	Volumes (2) Mcf	Base Rate (3) $/Mcf	Revenue (4) $	Bills (5)	Volumes (6) Mcf	Base Rate (7) $/Mcf	Revenue (8) $	BMNR Bills (9=1+5)	BMNR Revenue (10=4+8) $
1	January 2008										
2	RESIDENTIAL										
3	GSR - Residential Service					GTR - Residential Transportation Service					
4	Customer Charge	101,770		12.35	1,256,860	24,592		12.35	303,711		
5	Commodity Charge:										
6	All Gas Consumed		1,420,251.5	1.8715	2,658,001		386,093.6	1.8715	722,574		
7	Total	101,770	1,420,251.5		3,914,861	24,592	386,093.6		1,026,285	126,362	4,941,146
8	February 2008										
9	RESIDENTIAL										
10	GSR - Residential Service					GTR - Residential Transportation Service					
11	Customer Charge	101,140		12.35	1,249,079	25,510		12.35	315,049		
12	Commodity Charge:										
13	All Gas Consumed		1,375,434.2	1.872	2,574,125		389,019.8	1.8715	728,051		
14	Total	101,140	1,375,434.2		3,823,204	25,510	389,019.8		1,043,100	126,650	4,866,304
15	March 2008										
16	RESIDENTIAL										
17	GSR - Residential Service					GTR - Residential Transportation Service					
18	Customer Charge	101,335		12.35	1,251,487	25,658		12.35	316,876		
19	Commodity Charge:										
20	All Gas Consumed		1,106,329.3	1.872	2,070,495		315,568.4	1.8715	590,586		
21	Total	101,335	1,106,329.3		3,321,982	25,658	315,568.4		907,462	126,993	4,229,444
22	April 2008										
23	RESIDENTIAL										
24	GSR - Residential Service					GTR - Residential Transportation Service					
25	Customer Charge	100,316		12.35	1,238,903	25,819		12.35	318,865		
26	Commodity Charge:										
27	All Gas Consumed		692,345.5	1.872	1,295,725		206,889.9	1.8715	387,194		
28	Total	100,316	692,345.5		2,534,628	25,819	206,889.9		706,059	126,135	3,240,687
29	May 2008										
30	RESIDENTIAL										
31	GSR - Residential Service					GTR - Residential Transportation Service					
32	Customer Charge	99,647		12.35	1,230,640	25,653		12.35	316,815		
33	Commodity Charge:										
34	All Gas Consumed		275,779.5	1.872	516,121		83,451.6	1.8715	156,180		
35	Total	99,647	275,779.5		1,746,761	25,653	83,451.6		472,995	125,300	2,219,756

Columbia Gas of Kentucky Inc.
Revenue @ Current Rates Based on Weather Normalized Volumes
For the 12 Months Ending December 31, 2008

Line No.	Description	Bills (1)	Volumes (2) Mcf	Base Rate (3) $/Mcf	Revenue (4) $	Bills (5)	Volumes (6) Mcf	Base Rate (7) $/Mcf	Revenue (8) $	BMNR Bills (9=1+5)	BMNR Revenue (10=4+8) $
36	June 2008										
37	RESIDENTIAL										
38	GSR - Residential Service					GTR - Residential Transportation Service					
39	Customer Charge	98,366		12.35	1,214,820	26,021		12.35	321,359		
40	Commodity Charge:										
41	All Gas Consumed		142,073.6	1.872	265,891		42,706.9	1.8715	79,926		
42	Total	98,366	142,073.6		1,480,711	26,021	42,706.9		401,285	124,387	1,881,996
43	July 2008										
44	RESIDENTIAL										
45	GSR - Residential Service					GTR - Residential Transportation Service					
46	Customer Charge	97,709		12.35	1,206,706	25,815		12.35	318,815		
47	Commodity Charge:										
48	All Gas Consumed		101,520.7	1.872	189,996		29,918.8	1.8715	55,993		
49	Total	97,709	101,520.7		1,396,702	25,815	29,918.8		374,808	123,524	1,771,510
50	August 2008										
51	RESIDENTIAL										
52	GSR - Residential Service					GTR - Residential Transportation Service					
53	Customer Charge	97,071		12.35	1,198,827	25,951		12.35	320,495		
54	Commodity Charge:										
55	All Gas Consumed		95,735.5	1.872	179,169		26,763.2	1.8715	50,087		
56	Total	97,071	95,735.5		1,377,996	25,951	26,763.2		370,582	123,022	1,748,578
57	September 2008										
58	RESIDENTIAL										
59	GSR - Residential Service					GTR - Residential Transportation Service					
60	Customer Charge	96,206		12.35	1,188,144	25,955		12.35	320,544		
61	Commodity Charge:										
62	All Gas Consumed		93,605.4	1.872	175,183		28,251.8	1.8715	52,873		
63	Total	96,206	93,605.4		1,363,327	25,955	28,251.8		373,417	122,161	1,736,744
64	October 2008										
65	RESIDENTIAL										
66	GSR - Residential Service					GTR - Residential Transportation Service					
67	Customer Charge	96,505		12.35	1,191,837	26,077		12.35	322,051		
68	Commodity Charge:										
69	All Gas Consumed		142,597.9	1.872	266,872		42,635.0	1.8715	79,791		
70	Total	96,505	142,597.9		1,458,709	26,077	42,635.0		401,842	122,582	1,860,551

Columbia Gas of Kentucky Inc.
Revenue @ Current Rates Based on Weather Normalized Volumes
For the 12 Months Ending December 31, 2008

Line No.	Description	Bills (1)	Volumes (2) Mcf	Base Rate (3) $/Mcf	Revenue (4) $	Bills (5)	Volumes (6) Mcf	Base Rate (7) $/Mcf	Revenue (8) $	BMNR Bills (9=1+5)	BMNR Revenue (10=4+8) $
71	November 2008										
72	RESIDENTIAL										
73	GSR - Residential Service					GTR - Residential Transportation Service					
74	Customer Charge	97,390		12.35	1,202,767	26,527		12.35	327,608		
75	Commodity Charge:										
76	All Gas Consumed		416,076.4	1.872	778,687		133,478.3	1.8715	249,805		
77	Total	97,390	416,076.4		1,981,454	26,527	133,478.3		577,413	123,917	2,558,867
78	December 2008										
79	RESIDENTIAL										
80	GSR - Residential Service					GTR - Residential Transportation Service					
81	Customer Charge	97,676		12.35	1,206,299	27,387		12.35	338,229		
82	Commodity Charge:										
83	All Gas Consumed		963,942.9	1.872	1,804,019		310,742.9	1.8715	581,555		
84	Total	97,676	963,942.9		3,010,318	27,387	310,742.9		919,784	125,063	3,930,102
85	12 Months Ending December 2008										
86	RESIDENTIAL										
87	GSR - Residential Service					GTR - Residential Transportation Service					
88	Customer Charge	1,185,131		12.35	14,636,368	310,965		12.35	3,840,418		
89	Commodity Charge:										
90	All Gas Consumed		6,825,692.4	1.872	12,774,283		1,995,520.2	1.8715	3,734,616		
91	Total	1,185,131	6,825,692.4		27,410,651	310,965	1,995,520.2		7,575,034	1,496,096	34,985,685

Columbia Gas of Kentucky Inc.
Base Monthly Normalized Non-Gas Revenue Per Bill (BMNR)
For the 12 Months Ending December 31, 2008

Residential

Line No.	Month	BMNR Rate Schedules GSR and GTR Non-Gas Revenue	BMNR Rate Schedules RS, RTS, and EDS Customers	Calculated Monthly BMNR
(1)	(2)	(3)	(4)	(5=3/4)
1	January	$4,941,146	126,362	$39.10
2	February	4,866,304	126,650	38.42
3	March	4,229,444	126,993	33.30
4	April	3,240,687	126,135	25.69
5	May	2,219,756	125,300	17.72
6	June	1,881,996	124,387	15.13
7	July	1,771,510	123,524	14.34
8	August	1,748,578	123,022	14.21
9	September	1,736,744	122,161	14.22
10	October	1,860,551	122,582	15.18
11	November	2,558,867	123,917	20.65
12	December	3,930,102	125,063	31.42
13	Allowed Distribution Revenue per Customer			$279.38

Columbia Gas of Kentucky Inc.
Authorized Monthly Normalized Non-Gas Revenue (AMNR)
For the 12 Months Ending December 31, 2012

Residential

Line No. (1)	Month (2)	Actual 2012 Bills (3)	BMNR (4)	AMNR (5 = 3 x 4)
1	January	121,223	$39.10	$4,739,819
2	February	121,227	38.42	4,657,541
3	March	121,087	33.30	4,032,197
4	April	120,173	25.69	3,087,244
5	May	119,516	17.72	2,117,824
6	June	118,879	15.13	1,798,639
7	July	118,193	14.34	1,694,888
8	August	117,850	14.21	1,674,649
9	September	117,758	14.22	1,674,519
10	October	118,330	15.18	1,796,249
11	November	119,508	20.65	2,467,840
12	December	120,414	31.42	3,783,408
13	Total	119,513	$279.38	$33,524,817

Columbia Gas of Kentucky, Inc.
Revenue Normalization Adjustment Billing Factor (RNABF) - Computational Example
Residential Service

Line No.	Description		2012 January	February	March	1st Quarter
	(1)		(2)	(3)	(4)	(5)
1	Authorized Quarterly Non-Gas Revenue (AQNR) - Rate Schedules GSR and SVGTS GSR		$4,739,819	$4,657,541	$4,032,197	$13,429,557
2	Less: Weather Adjusted Quarterly Booked Revenue (WAQBR) - Rate Schedule GSR		$ 3,624,389	$ 3,448,168	$ 2,934,402	$ 10,006,959
3	Less: Weather Adjusted Quarterly Booked Revenue (WAQBR) - Rate Schedule SVGTS GSR		$ 1,132,609	$ 1,068,142	$ 909,585	$ 3,110,336
4	Subtotal	(Lines 2 + 3)				$ 13,117,295
5	Revenue Normalization Adjustment (RNA)	(Lines 1 - 4)				$ 312,262
6	Under/(Over) Collection from Prior Period (1)					$ -
7	Subtotal	(Lines 5 + 6)				$ 312,262
			June	July	August	3-Month Total
8	Estimated Normalized Gas Volumes (Mcf) - Rate Schedule GSR (2)		119,592	92,438	83,690	295,720
9	Estimated Normalized Gas Volumes (Mcf) - Rate Schedule SVGTS GSR (2)		37,233	28,256	25,802	91,291
10	Subtotal	(Lines 8 + 9)				387,011
11	RNA Billing Factor (RNABF)	(Line 7/Line 10)				$ 0.8069

(1) For the second preceding RNA Billing Period

Columbia Gas of Kentucky, Inc.
Financial Plan Volumes By Rate Schedule

Residential Sales

2012	2012
Jan	1,376,349
Feb	1,306,693
Mar	998,011
Apr	462,314
May	251,216
Jun	119,592
Jul	92,438
Aug	83,690
Sep	92,685
Oct	146,057
Nov	417,400
Dec	906,321
	6,252,766

Residential Choice

2012	2012
Jan	443,648
Feb	417,291
Mar	321,147
Apr	154,914
May	84,159
Jun	37,233
Jul	28,256
Aug	25,802
Sep	27,566
Oct	47,058
Nov	132,896
Dec	277,995
	1,997,965

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

57. Provide the calculation shown in Attachment RAF-7 for the first quarter of 2013.

Response:

Please refer to Attachment A.

Columbia Gas of Kentucky, Inc.
Revenue Normalization Adjustment Billing Factor (RNABF) - First Quarter 2013
Residential Service

Line No.	Description (1)		2013 January (2)	February (3)	March (4)	1st Quarter (5)
1	Authorized Quarterly Non-Gas Revenue (AQNR) - Rate Schedules GSR and SVGTS GSR		$4,725,782	$4,650,549	$4,031,032	$13,407,363
2	Less: Weather Adjusted Quarterly Booked Revenue (WAQBR) - Rate Schedule GSR		$ 3,725,639	$ 3,593,416	$ 3,089,309	$ 10,408,363
3	Less: Weather Adjusted Quarterly Booked Revenue (WAQBR) - Rate Schedule SVGTS GSR		$ 1,080,626	$ 1,023,607	$ 873,229	$ 2,977,462
4	Subtotal	(Lines 2 + 3)				$ 13,385,825
5	Revenue Normalization Adjustment (RNA)	(Lines 1 - 4)				$ 21,538
6	Under/(Over) Collection from Prior Period (1)					$ -
7	Subtotal	(Lines 5 + 6)				$ 21,538
			June	July	August	3-Month Total
8	Estimated Normalized Gas Volumes (Mcf) - Rate Schedule GSR (2)		129,925	87,956	84,915	302,795
9	Estimated Normalized Gas Volumes (Mcf) - Rate Schedule SVGTS GSR (2)		40,000	27,000	26,000	93,000
10	Subtotal	(Lines 8 + 9)				395,795
11	RNA Billing Factor (RNABF)	(Line 7/Line 10)				$ 0.0544

(1) For the second preceding RNA Billing Period

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

58. Refer to Attachment RAF-8. Confirm that the simulation of the operation of the RNA mechanism contained in this attachment shows that, for the three years ending December 31, 2012, the net under collection of AQNR to be recovered through the RNA is .25 percent as shown by the calculation below:

Time Period	AQNR	RNA	Percent
TME December 2012	$33,524,817	$555,816	
TME December 2011	$33,707,401	($344,758)	
TME December 2010	$33,886,227	$43,639	
Total 36 months ended December 2012	$101,118,445	$254,697	.2519%

Response:

The mathematical calculation is confirmed.

**COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013**

59. Refer to Tab 59. Provide an electronic copy of all schedules under this tab with the formulas intact and unprotected and all rows and columns accessible.

Response:

Please refer to the response to Staff's Data Request Set Two No. 4.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

60. Refer to Tab 59, Schedule 2.

a. Refer to pages 1-13 of 144. These pages show allocations to the following rate categories: GS-Res, GS-Other, IUS, DS-ML/SC, and DS/IS. Provide a listing of Columbia's individual rate classes that are included in each category.

b. Refer to pages 14-25 of 144. State whether Columbia engages in natural gas production. If the response is no, explain why there are line items allocated to the Production function.

c. Refer to page 20 of 144 and Schedule 4, page 5 of 16. Accounts 920-926 on page 20 of 144 are functionalized using the allocation factor LABOR. Schedule 4, page 5 of 16 provides the allocation percentage as 100 percent to Distribution. Explain in detail how this allocation factor was calculated including the accounts or line items included in the calculation.

d. Refer to page 38 of 144. Provide the rationale for allocating Miscellaneous Intangible Plant, Account 303, on the basis of the CUST allocation factor.

e. Refer to pages 39 and 45 of 144. Explain why Structures and Improvements, Account 375, is allocated using the DISTPT allocation factor on page 39, but depreciation expense on Distribution Land Structures and Improvements is allocated using the DEMAND allocation factor on page 45.

f. Refer to page 43 of 144 and Schedule 4, page 6 of 16. Operation Supervision and Engineering is allocated using the DISTLABOR allocation factor on page 43 of 144. Schedule 4, page 6 of 16 provides the allocation percentages as 19.65 percent to Demand, .2 percent to Commodity and 80.15 percent to Customer. Explain in detail how the DISTLABOR allocation percentages were calculated, including the accounts or line items included in the calculation.

g. Refer to page 45 of 144 and Schedule 4, page 6 of 16. Several accounts on page 45 of 144 are allocated based on the DISTL/P allocation factor. Schedule 4, page 6 of 16 provides the allocation percentages as 20.01 percent to Demand, .18 percent to Commodity and 79.80 percent to Customer. Explain in detail how the DISTL/P allocation percentages were calculated including the accounts or line items included in the calculation.

h. Refer to page 122 of 144. Explain the rationale for allocating Land-LNG Plant using the DesignDayxMDS allocation factor.

Response:

a-h. Please refer to Columbia's response to Staff data request number 2-5.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

61. Refer to Volume 9 of the application, the Direct Testimony of S. Mark Katko ("Katko Testimony"), page 9, lines 11-13, and the response to Item 35 of Staffs First Request.

a. Clarify whether the "[o]verall wage increase guideline of 3% for 2013 and 2014" is intended to mean 3 percent for the two years cumulatively or for each of the two years individually.

b. The data response shows increases of less than 3 percent in the base and forecast periods for union employees and in the base period for non-exempt non-union employees. Reconcile this with the 3 percent in the testimony.

Response:

a. The overall wage guideline increase is 3 percent for the two years individually.

b. The reference to an overall 3% wage increase each year in testimony is a general statement regarding calendar years 2013 and 2014. More specifically, the actual portion of the base period includes a union increase of 2% effective December 1, 2012 and a 2.5% increase for the budgeted portion, a non-exempt non-union increase of 2.5% effective June 1, 2013, and an exempt increase of 3% effective June 1, 2013. To develop an estimate of 2014 net labor expense, which is the forecasted test period, Columbia's budget applied a 3% increase to 2013 net labor expense. This is a reasonable estimate considering that a union increase of 3% effective December 1, 2013 impacts eleven months of the forecasted test period and all other increases are projected at 3% during 2014.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

62. Refer to Volume 9 of the application, the Direct Testimony of John J. Spanos ("Spanos Testimony"), and Tab 56, which is the depreciation study prepared for Columbia that is being sponsored by Mr. Spanos.

a. Page 6, line 15 of the Spanos Testimony indicates that Mr. Spanos has previously performed depreciation studies for Columbia. Provide the case numbers of all cases in which Mr. Spanos sponsored a depreciation study on behalf of Columbia.

b. The stipulation approved by the Commission in Case No. 200900141[3] stated that "Columbia's current depreciation rates will continue to be used. . . ." For how long have Columbia's current depreciation rates been in effect?

c. The table on pages III-4 and III-5 of the depreciation study shows, among other things, the depreciation rates developed within the study, resulting annual depreciation accruals, and the original cost of Columbia's utility

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[3] Case No. 2009-00141, Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates (Ky. PSC Oct. 26, 2009).

plant, all on an account-specific basis, based on plant balances as of December 31, 2012. Provide, in a similar format, a table using average plant balances in the forecasted test year which contains a side-by-side comparison of Columbia's current and proposed depreciation rates and the annual depreciation expense derived from each set of rates, by account and in total.

Response:

a. Mr. Spanos has conducted depreciation studies for Columbia Gas of Kentucky as of 12/31/2001, 12/31/2005, 12/31/2008 and 12/31/2012. The previous cases that Mr. Spanos was involved were PSC Case No. 2002-00145, PSC Case No. 2007-00008 and PSC Case No. 2009-00141.

b. Columbia's current depreciation rates have been in effect since March 1, 2003.

c. Mr. Spanos does not have the data necessary to calculate the average plant balances in the forecasted test year. However, Attachment A is the comparison of the proposed depreciation rates and expense versus the current depreciation rates and proforma expense as of December 31, 2012.

COLUMBIA GAS OF KENTUCKY, INC.

ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2012

	Depreciable Group	Original Cost at December 31, 2012	Book Reserve	Proposed Annual Accrual Rate	Proposed Annual Accrual Amount	Current Accrual Rate	Proforma Depreciation Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(2)*(6)
	DEPRECIABLE PLANT						
	DISTRIBUTION PLANT						
	Land and Land Rights						
374.4	Land Rights	616,570.15	140,226	1.79	11,011	1.53	9,434
374.5	Rights-of-Way	2,666,571.20	803,512	1.28	34,261	1.22	32,532
	Total Account 374	3,283,141.35	943,738	1.38	45,272		41,966
	Structures and Improvements						
375.34	Measuring and Regulating	1,142,576.46	408,231	3.00	34,253	1.96	22,394
375.7	Other Distribution System						
	Other Buildings	7,032,785.62	2,610,279	2.01	141,644	1.99	139,952
	Distribution System Structures	130,419.64	79,736	2.49	3,251	3.03	3,952
	Total Account 375.70	7,163,205.26	2,690,015	2.02	144,895		143,904
375.8	Communication Structures	33,260.58	32,864	0.10	33	5.32	1,769
	Total Account 375	8,339,042.30	3,131,110	2.15	179,181		168,067
376	Mains						
	Cast Iron	273,248.40	218,796	1.85	5,053	1.57	4,290
	Bare Steel	17,968,304.52	13,921,391	1.92	345,328	1.57	282,102
	Coated Steel	44,837,223.36	13,448,290	2.00	896,157	1.57	703,944
	Plastic	98,419,204.15	24,021,168	2.14	2,102,387	1.57	1,545,182
	Total Account 376	161,497,980.43	51,609,645	2.07	3,348,925		2,535,518
378	Meas and Reg Sta. Equip. - General	5,401,380.31	2,717,630	2.71	146,348	2.35	126,932
379.1	Meas and Reg Sta. Equip. - City Gate	257,908.74	270,760	0.40	1,037	2.27	5,855
380	Services	95,861,712.15	54,739,756	4.62	4,427,524	2.59	2,482,818
381	Meters	12,169,558.60	4,192,116	3.70	450,264	2.59	315,192
381.1	Meters - AMI	682,384.32	15,881	7.75	52,862	7.75 *	52,885
382	Meter Installations	8,234,752.85	3,926,752	2.96	243,774	2.39	196,811
383	House Regulators	4,884,766.35	1,239,809	3.04	148,398	1.39	67,898
384	House Regulator Installations	2,282,263.96	1,696,055	1.31	29,963	1.10	25,105
385	Industrial Meas and Reg Equipment	2,763,500.00	940,969	4.61	127,459	2.09	57,757
387.4	Other Equipment - Customer Information Services	3,275,691.89	1,364,584	3.63	118,876	2.34	76,651
	TOTAL DISTRIBUTION PLANT	308,934,083.25	126,788,805	3.02	9,319,883		6,153,455

COLUMBIA GAS OF KENTUCKY, INC.

ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2012

	Depreciable Group (1)	Original Cost at December 31, 2012 (2)	Book Reserve (3)	Proposed Annual Accrual Rate (4)	Proposed Annual Accrual Amount (5)	Current Accrual Rate (6)	Proforma Depreciation Expense (7)=(2)*(6)
GENERAL PLANT							
	Office Furniture and Equipment						
391.1	Furniture	1,136,231.33	1,007,199	5.00	56,825	5.00	56,812
391.11	Equipment	23,574.97	11,776	6.67	1,573	6.67	1,572
391.12	Information Systems						
	Fully Accrued	1,820.65	1,821	-	0	-	0
	Amortized	615,447.42	198,141	20.00	123,116	20.00	123,089
	Total Account 391.12	617,268.07	199,962	19.95	123,116		123,089
392.2	Transportation Equipment - Trailers	139,968.44	38,749	7.33	10,256	6.34	8,874
	Tools, Shop and Garage Equipment						
394	Equipment	2,219,703.21	1,069,603	4.00	88,683	4.00	88,788
394.11	CNG Facilities	335,308.07	249,148	7.85	26,314	13.77	46,172
	Total 394	2,555,011.28	1,318,751	4.50	114,997		134,960
395	Laboratory Equipment	9,781.80	6,175	5.00	489	5.00	489
396	Power Operated Equipment	258,254.72	83,967	5.98	15,448	-	0
398	Miscellaneous Equipment						
	Fully Accrued	3,290.19	3,290	-	0	-	0
	Amortized	119,675.52	47,452	6.67	7,981	6.67	7,982
	Total Account398	122,965.71	50,742	6.49	7,981		7,982
TOTAL GENERAL PLANT		4,863,056.32	2,717,321	6.80	330,685		333,778
TOTAL DEPRECIABLE PLANT		313,797,139.57	129,506,126	3.08	9,650,568		6,487,233
UNRECOVERED RESERVE TO BE AMORTIZED							
391.1	Furniture		(78,543)		26,181 ***		
391.11	Equipment		(1,342)		447 ***		
391.12	Information Systems		(1,102)		367 ***		
394	Equipment		(50,635)		16,878 ***		
395	Laboratory Equipment		2		(1) ***		
398	Miscellaneous Equipment		(1,628)		543 ***		
TOTAL UNRECOVERED RESERVE TO BE AMORTIZED			(133,248)		44,416		0

COLUMBIA GAS OF KENTUCKY, INC.

ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2012

	Depreciable Group	Original Cost at December 31, 2012	Book Reserve	Proposed Annual Accrual Rate	Proposed Annual Accrual Amount	Current Accrual Rate	Proforma Depreciation Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(2)*(6)
AMORTIZABLE PLANT							
303	Misc. Intangible Plant	2,924,339.05	1,187,281	**	1,149,329	**	1,149,329
375.71	Structures and Improvements - Leaseholds	63,643.11	25,916	**	25,916	**	25,916
TOTAL AMORTIZABLE PLANT		2,987,982.16	1,213,197		1,175,245		1,175,245
NONDEPRECIABLE PLANT							
301	Organization	521.20					
304	Land	7,678.39					
374.1	Land	206.00	(19)				
374.2	Land	878,533.97					
TOTAL NONDEPRECIABLE PLANT		886,939.56	(19)				
TOTAL GAS PLANT		317,672,061.29	130,586,056		10,870,229		7,662,478

* Utilized proposed rate as no rate existed as of prior case.
** Accrual rate based on individual asset amortization.
*** 3-Year amortization of unrecovered reserve related to implementation of amortization accounting.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

63. Refer to Volume 9 of the application, the Direct Testimony of Susanne M. Taylor ("Taylor Testimony"), page 6, lines 1 through 6, where it states, "[c]ontract billed charges may be direct (billed directly to a single affiliate or affiliates) or allocated (split between or among several affiliates), depending on the nature of the expense." For the forecasted period, provide the amount of contract billed charges broken down by direct charges and allocated charges.

Response:

This information is not available for the forecasted test period. During the NiSource Corporate Services Company budgeting process, departments determine how to allocate their budgets to each company for which they perform services and this determination results in a management fee billing budget for each company including Columbia. Amounts attributable to each specific allocation are not retained.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

64. Refer to page 10 of the Taylor Testimony where Ms. Taylor discusses the Federal Energy Regulatory Commission ("FERC") audit of NiSource Services for which a final report was issued October 24, 2012.

a. Provide the October 24, 2012 FERC audit report.

b. Explain whether this was the first FERC audit of NiSource Services since the NiSource/Columbia merger.

c. If there have been other FERC audits of NiSource Services since the NiSource/Columbia merger, provide the reports of those audits.

d. Explain whether there is a specific timetable or frequency for future FERC audits of NiSource Services.

Response:

a. Please see PSC-02-064 Attachment A hereto for a copy of the October 24, 2012 FERC audit report.

b. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the U. S. Securities and Exchange Commission ("SEC") to the Federal Energy Regulatory Commission ("FERC") on February 8, 2006. Therefore, this is the first FERC audit of NiSource Corporate Services Company (NCSC) since the NiSource/Columbia merger.

c. There have not been any other FERC audits of NiSource Services since the NiSource/Columbia merger.

d. There is no specific timetable or frequency for future FERC audits of NCSC. However, NCSC files a Form 60 with the FERC on an annual basis on May 1st of each year.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. FA11-5-000
October 24, 2012

NiSource Inc.
Attention: Stephen P. Smith
Executive Vice President and Chief Financial Officer
801 East 86th Ave.
Merrillville, IN 46410

Dear Mr. Smith:

1. The Division of Audits within the Office of Enforcement (OE) has completed the audit of NiSource Inc. (NiSource or Company) and its associated companies from January 1, 2009 through December 31, 2010. The enclosed audit report explains our audit findings and recommendations.

2. On August 21, 2012, you notified us that NiSource agrees with our findings and recommendations. A copy of your verbatim response is included as an appendix to this report. I hereby approve the audit findings and recommended corrective actions. Within 30 days of this letter order, NiSource should submit a plan to comply with the corrective actions. NiSource should make quarterly filings describing how and when it plans to comply with the corrective actions, including dates it has completed each corrective action. The submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

3. The Commission delegated the authority to act on this matter to the Director of OE under 18 C.F.R. § 375.311 (2011). This letter order constitutes final agency action. Your Company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2011).

4. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of noncompliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

5. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director and Chief Accountant, Division of Audits at (202) 502-8741.

Sincerely,

Norman C. Bay

Norman C. Bay
Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission

Audit of NiSource Inc. Affiliate Transactions, including its Compliance with:

- Cross-Subsidization Restrictions on Affiliate Transactions;
- Regulations Under the Public Utility Holding Company Act of 2005; and
- Uniform System of Accounts for Public Utilities and Natural Gas Companies' Accounting for Service Company Transactions

Docket No. FA11-5-000
October 24, 2012

Office of Enforcement
Division of Audits

TABLE OF CONTENTS

I. Executive Summary

A. Overview

The Division of Audits within the Office of Enforcement has completed an audit of NiSource Inc. (NiSource or the Company) including its service companies, and associated companies (collectively Companies). The audit was initiated to evaluate the Companies' compliance with the Federal Energy Regulatory Commission's (FERC or the Commission's): (1) cross-subsidization restrictions on affiliate transactions under 18 C.F.R. Part 35 (2010); (2) accounting, recordkeeping, and reporting requirements under 18 C.F.R. Part 366 (2010); (3) Uniform System of Accounts (USofA) for centralized service companies under 18 C.F.R. Part 367 (2010); (4) preservation of records requirements for holding companies and service companies under 18 C.F.R. Part 368 (2010); and (5) FERC Form No. 60 Annual Report requirements under 18 C.F.R. Part 369 (2010).

The audit also evaluated the associated public utility and natural gas companies' compliance with the Commission's accounting requirements for transactions with associated companies under 18 C.F.R. Parts 101 and 201 (2010), and the applicable reporting requirements in the FERC Form Nos. 1 and 2. The audit period covered January 1, 2009 through December 31, 2010.

B. NiSource Inc.

NiSource, headquartered in Merrillville, IN, is an energy holding company whose subsidiaries provide natural gas, electricity, and other products and services to approximately 3.8 million customers in a corridor that runs from the Gulf Coast through the Midwest to New England.

NiSource is organized into three primary business segments. The Gas Transmission and Storage Operations business segment operates interstate natural gas pipelines and storage facilities. NiSource's natural gas transmission subsidiaries include Columbia Gulf Transmission Company (CGT), Columbia Gas Transmission Company (TCO), Granite State, and others. NiSource's electric operation segment generates, transmits, and distributes electricity through its domestic public utility subsidiary, Northern Indiana Public Service Company (NIPSCO), to approximately 458,000 customers in 20 counties in northern Indiana. NiSource's natural gas distribution operations segment serves more than 3.3 million customers in seven states and operates approximately 59,000 miles of pipeline.

NiSource affiliates are served by two traditional centralized service companies, NiSource Corporate Services Company (NCSC) and NiSource Gas Transmission & Storage Company (NGTSC). Both service companies generally provide human capital services that include accounting, human resources, legal, and information technology support. NCSC provides human capital services to all of NiSource's subsidiaries, whereas NGTSC provides human capital services to only Columbia Gulf Transmission Company, one of NiSource's interstate gas transmission pipeline and storage companies.

C. Summary of Compliance Findings

Audit staff's compliance findings are summarized below. Details are in section IV of this report. Audit staff found eight areas of noncompliance:

- *Electric Public Utility's Accounting for Billings from the Service Company:* NIPSCO did not record some of the costs it received from NCSC in the appropriate accounts as required by the Commission's accounting regulations.

- *Prepayment for the use of Finance and Accounting Transformation Servers:* NCSC improperly accounted for a prepayment for the use of accounting servers in Account 186, Miscellaneous Deferred Debits, when it should have accounted for this prepayment in Account 165, Prepayments.

- *Accounting for Over-Funding of a Single-Employer, Defined Post-Retirement Benefit Plan:* NCSC inappropriately recorded the overfunding of a single-employer, defined post-retirement life insurance benefit plan in Account 186, Miscellaneous Deferred Debits, for 2009 and 2010. The Company should have recorded the overfunded status in Account 128, Other Special Funds.

- *Improperly Recorded Transferred Employee Benefits:* NCSC improperly recorded transferred employee benefits in Account 186, Miscellaneous Deferred Debits, for 2009 and 2010. The Company should have recorded these benefits in Account 146, Accounts Receivable from Associated Companies, until they were paid.

- *FERC-61Reporting:* NiSource did not submit FERC-61, Narrative Description of Service Company Functions, filings for three special-purpose companies between 2006 and 2010, as the Commission regulations require.

- *Untimely Filing for Cash Management Agreement:* NiSource did not file changes to its cash management agreement within 10 days of the change in one occurrence during the audit period, as Commission regulations require.

- *Reporting of Transactions with Associated (Affiliated) Companies:* NiSource's public utility affiliate, NIPSCO, did not report the required information on page 429, Transactions with Associated (Affiliated) Companies, in the FERC Form No. 1s filed in 2009 and 2010. NiSource's natural gas pipeline and storage affiliates, TCO and CGT, did not report the required information on page 358, Transactions with Associated (Affiliated) Companies, in the FERC Form No. 2s filed in 2009 and 2010. Specifically, each entity did not report the accounts charged or credited for certain non-power goods and services provided for or by affiliates.

- *Miscellaneous Accounting Classification Errors:* NCSC improperly classified certain expenses in the wrong FERC accounts. NCSC should have classified these transactions in the proper accounts as the USofA for centralized service companies prescribed under 18 C.F.R. Part 367.

D. Summary of Recommendations

Audit staff's recommendations to remedy these findings are summarized below. Details are discussed in section IV of this report. To address each area of non-compliance, audit staff recommends that NiSource:

- Develop and implement policies and procedures to ensure that NCSC and NIPSCO comply with the Commission's accounting regulations for billings from NCSC.

- Conduct a study from the beginning of the audit period to present to determine the accuracy of the accounts that NIPSCO used to reallocate and record service company billings, and submit the results of this study to audit staff. NiSource should complete this study and submit it to the DA no later than 180 days after the date this audit report is issued.

- Make correcting entries to NIPSCO's accounting records to properly classify all charges the service company billed from the beginning of the audit period to present, and submit these journal entries to audit staff.

- Require NCSC to reclassify the remaining noncurrent prepayment portion of the finance and accounting transformation servers to Account 165.

- Reclassify the overfunded portion of its postretirement life insurance benefit from Account 186 to Account 128 for compliance with Docket No. IA07-1-000.

- Develop policies to ensure that long-term disability insurance for transferred employees is properly accounted for in Account 146.

- Develop and implement a process that periodically reviews all corporate entities that require a FERC-61 filing.

- Develop and/or strengthen policies and procedures for submitting its cash management agreements and subsequent changes or modifications to ensure compliance with Commission filing requirements.

- Strengthen its policies and procedures for submitting data on its FERC Form Nos. 1 and 2 to ensure accurate and complete reporting.

- Implement accounting policies, processes, and procedures to ensure the types of transactions indentified above are recorded according to Commission regulations.

- Post correcting entries to NCSC's accounting records to properly classify all lobbying and political activity charges from the beginning of the audit period to present.

E. Compliance and Implementation of Recommendations

Audit staff further recommends that NiSource:

- Submit its plans for implementing audit staff's recommendations for audit staff's review. NiSource should provide its plan to audit staff within 30 days of the issuance of the final audit report in this docket.

- Submit all correcting entries to the Division of Audits within 30 days of the issuance of the final audit report in this docket, including all correcting entries affecting the books of the service company and associated franchised public utility (FPU).

- Submit quarterly reports to the Division of Audits describing the Companies' progress in completing each corrective action recommended in the final audit report in this docket. NiSource should make its quarterly filings no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report in this docket is issued, and continuing until NiSource completes all recommended corrective actions.

- Submit copies of any written policies and procedures developed in response to the recommendations in the final audit report. These policies and procedures should be submitted for audit staff's review in the first quarterly filing after the Companies complete these items.

II. Background

A. Service Agreements, Cost Allocations, and Corporate Accounting System

The provisions of the General Service Agreement (GSA) between NCSC and NiSource's affiliates serve as the source of accounting policy and practice for billings of non-power goods and services. A regulated or nonregulated affiliate may select any or all of the services under the GSA. NCSC and its NiSource affiliates review their service agreements annually and agree on what NCSC services will be provided through budgeting. Such goods and services between affiliates are priced at fully allocated cost and to the extent possible, directly charged to the client or clients benefiting from a service. Any remaining charges that cannot be directly charged to an affiliate are allocated between the companies receiving the benefit of the service.

NCSC uses a central accounting system, also known as a work order system, to accumulate costs. This system is used to create and maintain all NCSC work orders, which receive all NCSC costs to bill the proper NiSource affiliate for work performed. The system also assigns a 10-digit alphanumeric code to the project or projects that details how expenses will be charged. The Company said much "front-end" work occurs in meetings between a department head working with an affiliate and NCSC personnel. These meetings help management build a consensus on how a new project's costs will be allocated to NiSource affiliates. Attendees at these meetings discuss the work that will take place to accurately determine which costs should be included in the work order system, the cost allocation base that should be used for the project, which companies benefit from the costs, and the portion of the cost each affiliate should receive and record in its accounting records.

Once NiSource management agrees to the basics of the newly created work order system project, costs are assigned using one of the base allocations[1] the Security and Exchange Commission (SEC) previously approved, or a direct company billing code. The work order system is designed so base allocations never change, but the companies that receive the costs can and do change. NCSC reviews and updates the amounts allocated to its affiliates every six months or

[1] The SEC approved all of NiSource's base allocations, and no other base allocations have been created since the Energy Policy Act of 2005 went into effect.

before, if an affiliated company is sold or no longer receives NCSC services.[2] Both the Company's external and internal auditors analyze the cost allocators yearly, and state public utility commissions also review the Company's cost allocations as they pertain to filed rate cases. The Company said NiSource has never had a cost allocation refused by a regulatory authority.

NCSC's total billings to associated companies for 2009 were $377,469,976. Of that, $276,719,054 was direct-charged (73.3 percent); $99,430,359 (26.3 percent) was indirectly charged; and $1,320,563 (0.3 percent) was compensation for the use of capital. Compensation for the use of capital represents interest expense paid on long-term intercompany notes.

NCSC's total billings to associated companies for 2010 were $409,702,831. Of that, $302,753,123 was direct-charged (73.9 percent); $105,629,146 (25.8 percent) was indirectly charged; and $1,320,562 (0.3 percent) was compensation for the use of capital.

B. Internal Audit Role and Reporting

NiSource's Internal Audit department (Internal Audit) is responsible for reviewing accounting systems, source documents, allocation bases, and billing procedures NCSC used to allocate costs to NiSource's parent holding company and all of its subsidiaries.

Annually, Internal Audit reviews cost allocation bases and billing procedures NCSC uses and recommends improvements to allocation and billing processes. For 2010, the primary business risks associated with these activities were that:

- Allocation factors may not be updated regularly to reflect current statistical data to ensure that NCSC charges are billed relative to current operations;
- Contract and convenience billings may not be properly billed to affiliates;
- Holding company costs may not be properly segregated and paid by the holding company;

[2] If an affiliate that receives allocated costs is sold, the cost allocations it participates in are updated. When an update occurs, the entire allocation system is updated.

- Executive time allocation may not accurately reflect the companies benefiting from their services;

- Not all indirect costs may be appropriately allocated to affiliates monthly; and

- Intercompany payables and receivables may not be billed and settled accurately and on time.

The Internal Audit department performed the annual audit and concluded that the methods and procedures used to allocate costs/expenses and bill subsidiary Companies, including the holding company, were reasonable.

C. Formula Rates

NiSource has one electric FPU jurisdictional to FERC with formula rates, and that company is NIPSCO. NIPSCO is a combination electric and natural gas public utility company that is a transmission-owning member of the Midwest Independent Transmission Service Operator, Inc. (MISO), whose transmission rates are set under formula rate in Attachment O of the MISO Open Access Transmission Energy and Operating Reserve Energy Markets Tariff. Attachment O uses data from the FERC Form No. 1 as inputs to calculate certain transmission rates for service.

To provide rate stability and certainty, rates are updated May 1 of each year, and are not updated out of cycle or recalculated retroactively due to late submissions of information. When MISO is informed of an error in a rate calculation, it reviews and corrects the error prospectively. At the request of the transmission owner, MISO will retroactively recalculate rates, and make refunds and/or charges for the current billing year.

III. Introduction

A. Objectives

The audit's objectives were to evaluate whether the Companies complied with Commission: (1) cross-subsidization restrictions on affiliate transactions under 18 C.F.R. Part 35 (2010); (2) accounting, recordkeeping, and reporting requirements under 18 C.F.R. Part 366 (2010); (3) Uniform System of Accounts (USofA) for centralized service companies under 18 C.F.R. Part 367 (2010); (4) preservation of records requirements for holding companies and service companies under 18 C.F.R. Part 368 (2010); and (5) FERC Form No. 60 Annual Report requirements under 18 C.F.R. Part 369 (2010).

The audit also evaluated associated public utility and natural gas companies' compliance with Commission accounting requirements for transactions with associated companies under 18 C.F.R. Parts 101 and 201 (2010), respectively; and, the applicable reporting requirements in FERC Form Nos. 1 and 2, respectively. The audit covered January 1, 2009 through December 31, 2010.

B. Scope and Methodology

To address audit objectives, audit staff:

- Reviewed NCSC's FERC Form No. 60 Annual Reports and NiSource's notification of holding company status FERC-65 filing. Audit staff reviewed these reports and filings to ensure that the information was reliable, accurate, and complete.

- Reviewed publicly available materials to understand NiSource operations, including select filings to the SEC (10-K and 10-Q), FERC Form Nos. 1, 2, and 2-A filings, prior audits, and other filings with the Commission.

- Identified the standards and criteria for evaluating Company compliance with each of the objectives of the audit scope. These standards and criteria include FERC rules, regulations, letter orders, and other requirements for holding and service companies, and FERC accounting regulations related to public utilities and natural gas companies.

- Conducted one site visit to NiSource offices in Columbus, OH. The site visit helped staff to understand NiSource's structure, activities, functions, systems, and processes used in its operations. While on site, audit staff reviewed and tested the supporting details for NCSC's cost allocation methods; sampled and selected supporting documents to ensure that NCSC's billings and the FPU's accounting comply with the USofA; sampled and selected supporting documents to ensure that NCSC's accounting complies with the USofA; and ensured that NiSource and NCSC comply with preservation of records requirements.

- Held numerous discussions with Company employees to clarify and supplement Company responses to data requests and provide additional information on other areas of concern.

- Reviewed relevant audit reports and working papers of NiSource's Internal Audit department and external audit firm, Deloitte and Touche. Audit staff also reviewed several prior SEC audit reports.

- Conferred with officials from the Indiana Utility Regulatory Commission who have jurisdiction over NCSC's associated FPU.

- Conferred with other Commission staff on various compliance issues to ensure that audit findings would be wholly consistent with Commission precedent and policy. For example, audit staff conferred with staff from other divisions within the Office of Enforcement, and with technical and legal staff from other Commission offices, including the Office of Energy Market Regulation and Office of General Counsel.

Besides these actions, audit staff reviewed NiSource's regulatory compliance program. Audit staff assessed the compliance program for the audit scope areas consistent with prior Commission orders and policy statements. Specifically, audit staff:

- Reviewed NiSource's regulatory compliance program structure, including its authority and responsibilities for overseeing corporate compliance and the delegation of compliance responsibilities at the department level.

- Reviewed NiSource's Internal Audit department structure, including chain-of-command and access to the Board of Directors through the Audit Committee to assess the effectiveness and independence of the audit process.

- Interviewed executives, managers, and operational employees to evaluate their knowledge and application of NiSource's compliance program.

Audit staff performed several specific actions to evaluate the Companies' compliance with all relevant requirements of audit objectives. A summary of these actions include:

Cross-subsidization Restrictions

To evaluate compliance with Commission's cross-subsidization restrictions on affiliate transactions, audit staff:

- Reviewed policies, procedures, and practices as to the sale of non-power goods and services;
- Interviewed NiSource employees, particularly those who work in accounting and supply chain management on transfers of non-power goods and services;
- Reviewed and tested pricing methods for transferring non-power goods and services between the FPU, market-regulated power sales affiliates, and non-utility affiliates; and
- Sampled charges and payments to determine accurate pricing for the sale of goods and services to verify compliance with Commission pricing rules.

Accounting, Recordkeeping, and Financial Reporting

To evaluate compliance with the FERC's books, records, and filing requirements, audit staff reviewed NCSC's FERC Form No. 60 Annual Reports, NiSource's Notification of Holding Company Status – FERC-65 filing, and the FERC Form Nos. 1, 2, and 2-A reports of the associated FPU and natural gas companies. Select, electronically filed information in the FERC Form No. 60 was verified with supporting documentation to ensure that required information was reported accurately and consistently. Select information in the FERC Form No. 1 was also compared to the FERC Form No. 60 to ensure it was reported accurately.

To facilitate our review of NCSC's compliance with the USofA, audit staff reviewed, sampled, analyzed, and tested electronic data of NCSC's books to ensure that centralized service company accounting follows the USofA. When necessary, audit staff followed up with additional data requests and interviews.

With respect to the jurisdictional FPU's compliance with the Commission's USofA, audit staff selected and reviewed associated FPU accounts for NCSC's billed costs. Audit staff reviewed the charges billed and identified the accounts the FPU used to ensure that the jurisdictional FPU was properly accounting for service company costs.

We also reviewed NCSC's associated FPU accounting with the FERC Form No. 1 to ensure that NCSC billings for non-power goods and services were properly recorded and reported.

Preservation of Records

To evaluate compliance with preservation of records requirements for NiSource, audit staff interviewed the Company's Corporate Management Records officials responsible for complying with Commission requirements. Audit staff created a sample test for records to ensure that the Company's policies and procedures were being followed.

Cost Allocation and Billings

To facilitate our review of NCSC's cost allocation methods and costs NCSC billed to the associated FPU, audit staff identified all SEC-approved cost allocation methods by NCSC. Audit staff also inquired about any new allocation methods created after the Energy Policy Act of 2005 was implemented. Audit staff reviewed and tested supporting details of select cost allocation methods by reviewing select service company billings and corresponding jurisdictional utilities' accounting entries to determine compliance with the USofA.

IV. Findings and Recommendations

1. Electric Public Utility's Accounting for Billings from the Service Company

Northern Indiana Public Service Company (NIPSCO) did not record some of the costs it received from NCSC in the appropriate accounts as required by the Commission's accounting regulations.

Pertinent Guidance

18 C.F.R. Part 101 Account 163, Stores expense undistributed, states:

> A. This account shall include the cost of supervision, labor and expenses incurred in the operation of general storerooms, including purchasing, storage, handling and distribution of materials and supplies.

18 C.F.R. Parts 101 Account 182.3, Other regulatory assets, states in part:

> A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. (*See* Definition No. 30.)

18 C.F.R. Parts 201 Account 182.3, Other regulatory assets, states in part:

> A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. (*See* Definition No. 31.)

18 C.F.R. Parts 101 and 201 Account 923, Outside services employed, state in part:

> A. This account shall include the fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function or to other accounts. It shall include also the pay and expenses of persons engaged for a special or temporary administrative or general purpose in circumstances where the person so engaged is not considered as an employee of the utility.

18 C.F.R. Part 201, Account 870, Operation supervision and engineering, states:

> This account shall include the cost of labor and expenses incurred in the general supervision and direction of distribution system operations. Direct supervision of specific activities such as load dispatching, main operation, removing and resetting meters, etc., shall be charged to the appropriate account.

18 C.F.R. § 367.4261 Account 426.1, Donations, states:

> This account must include all payments or donations for charitable, social or community welfare purposes.

Order No. 684 Paragraph 124 states in part:

> Therefore, we will require centralized service companies to record the expenses it incurs for conducting operation and maintenance activities related to generation, transmission, distribution and customer services in the same expense accounts public utilities are required to use to record these costs. Using the 500 and 800 series of accounts also provides better assurance that costs are properly assigned because like items will be identified and measured in the same way regardless of the entity performing the work.

Order No. 684 Paragraph 125 states:

> In responding to NARUC's concern, we will not prohibit the recording of charges in Account 923, Outside services. Prohibiting the use of this account would be overly prescriptive. It is possible that some service company costs would be accurately reported in Account 923. However, we believe that it is appropriate for utilities that receive bills from service companies to classify those costs in the appropriate accounts. Utilities would not be in compliance with Part 101, General Instruction 14, if they do otherwise. Specifically, General Instruction 14 requires that transactions with associated companies be recorded in the appropriate accounts for transactions of the same nature. We will require that centralized service companies performing services such as operation and maintenance services related to generation, distribution, transmission, and customer service on behalf of service companies to use the appropriate accounts for those services performed.

Order No. 684 Paragraph 126 states in part:

> As discussed above, the use of the 500 and 800 accounts provides clarity about the types of services performed by centralized service companies and the costs of providing those services. Proper classification of service company costs facilitates proper classification of the costs at the utility. Therefore, we will require centralized service companies to use the 500 and 800 series of accounts as proposed.

Background

During the course of the audit, audit staff tested NIPSCO's accounting for billings received from NCSC, NiSource's primary service company. Audit staff sampled NCSC's transactions and costs billed to NIPSCO to determine how each company accounted for the billed costs. Audit staff discovered inconsistencies between how NCSC and NIPSCO recorded these costs. These inconsistencies occurred because NIPSCO reclassified these billed costs into accounts that differed from how NCSC accounted for these costs.

For example, NCSC billed certain costs to NIPSCO that it accounted for in Account 923, but NIPSCO reclassified some of these costs to Accounts 163, 870, and 182.3. Audit staff is concerned with NIPSCO's reclassifying these costs because the accounting used did reflect the appropriate accounting based on the description of the costs incurred. The costs reflected in the billings from the NCSC are of the nature of outside services that should be properly classified in Account 923. This would be consistent in how NCSC originally accounted for these costs.

Also, audit staff discovered the same inconsistency in NCSC's billings of amounts included in Account 426.1 to NIPSCO. NCSC billed NIPSCO for donations in Account 426.1, which is a below-the-line account,[3] but NIPSCO reclassified these billings to FERC operational Accounts 923 and 163. These transactions not only concern audit staff because the reclassification of service company billings did not result in the appropriate accounting for such costs, but in this instance NIPSCO reclassified these costs from a below-the-line to above-the-line accounts. Since NIPSCO recovers it costs under the MISO formula rate

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[3] The "line" is the net utility operating income on the income statement. Above-the-line accounts refer to costs that are recovered by the ratepayer and are accounted for as part of net utility operating income. Below-the-line accounts record costs that are the responsibility of the shareholder and are accounted for on the income statement below net utility operating income.

recovery mechanism, this reclassification was improperly recovered from wholesale customers.

NiSource believes it has complied with Order No. 684 because it allows service companies to use the 500 and 800 accounts to record charges related to generation, transmission, distribution operations, and customer service in the same expense accounts public utilities are required to use to record these costs. Audit staff agrees that Order No. 684 allows service companies to use the 500 and 800 accounts, but it does not circumvent General Instruction 14. Instead, Order No. 684 reaffirms General Instruction 14. Specifically, the instruction requires that transactions with associated companies be recorded in the appropriate accounts for transactions of the same nature. Audit staff determined that NiSource should have accounted for costs billed by NCSC in the appropriate accounts based on the Commission's accounting regulations, which means that it should have accounted for the outside services in Account 923 and donations in Account 426.1. The misclassifications resulted in a *de minimus* increase on NIPSCO's formula rate revenue requirement and did not result in refunds.

Recommendations

We recommend NiSource:

1. Develop and implement policies and procedures to ensure that NCSC and NIPSCO comply with the Commission's accounting regulations for billings from NCSC.

2. Conduct a study from the beginning of the audit period to present to determine the accuracy of the accounts that NIPSCO used to reallocate and record service company billings, and submit the results of this study to audit staff. NiSource should complete this study and submit it to the Division of Audits no later than 180 days after the date this audit report is issued.

3. Make correcting entries to NIPSCO's accounting records to properly classify all charges the service company billed from the beginning of the audit period to present, and submit these journal entries to audit staff.

2. Prepayment for the Use of Finance and Accounting Transformation Servers

NCSC improperly accounted for a prepayment for the use of accounting servers in Account 186, Miscellaneous Deferred Debits, when it should have accounted for this prepayment in Account 165, Prepayments.

Pertinent Guidance

18 C.F.R. § 367.1860 (a) Account 186, Miscellaneous deferred debits, states:

> (a) This account must include all debits not provided for elsewhere, such as miscellaneous work in progress, and unusual or extraordinary expenses, not included in other accounts, that are in the process of amortization and items the proper final disposition of which is uncertain.

18 C.F.R. § 367.1650 Account 165, Prepayments, states:

> This account must include amounts representing prepayments of insurance, rents, taxes, interest and miscellaneous items, and must be kept or supported in a manner so as to disclose the amount of each class of prepayment.

Background

As part of the audit, audit staff tested select accounts that had large increases or decreases during the audit period, or warranted further review due to unusual explanations or circumstances discussed in the notes for the FERC Form No. 60. During this process, audit staff learned that in 2005 NiSource wanted to outsource specific services in finance and accounting, IT, metering cash, human resources, supply chain, and storage services, and asked for bids from several companies that NiSource believed could adequately perform these services. IBM won the contract. These services were known as "towers," and these six towers made up the services IBM provided to NiSource. The 10-year term of the contract expires in June 2015.

From June 2005 to the fall of 2007, NiSource and IBM executed 22 amendments to this agreement. Due to the number of amendments to the 2005 agreement and other issues, NiSource and IBM agreed to negotiate to restructure the nature and manner of services being provided under the original agreement. NiSource and IBM agreed to execute the First Amended and Restated Agreement in December 2007.

In the First Amended and Restated Agreement, NiSource moved back in-house several functions originally outsourced to IBM in June 2005. They included, but were not limited to, finance and accounting, human resources, and supply chain. The cost of the original agreement was adjusted down to reflect the services provided by the newly scaled-back agreement. The term of the new agreement was for the original 10 years and will expire in June 2015.

When this transition occurred, both NiSource and IBM agreed to a financial settlement that included: (1) termination fees of $9.8 million paid to IBM and expensed immediately by NiSource in December 2007; (2) "wind-down" fees (IBM's fee to move work back to NiSource) of approximately $1 million that were immediately expensed on NiSource's books in December 2007 and another $1.2 million expensed over the time it took for the specific functions to be moved back to NiSource; (3) purchases of $2.4 million for meter-to-cash equipment, and $17.5 million for finance and accounting transformation software that NiSource capitalized; and (4) a $12 million prepayment for the future use and support of finance and accounting transformation servers in which the current monthly amortized portion was recorded in Account 165, Prepayments, and the noncurrent portion was accounted for in Account 186, Miscellaneous Deferred Debits. This prepayment is expensed monthly over the remaining term of the IBM contract (91 months) starting back in December 2007, or $131,868 per month ($12,000,000/91 months = $131,868).

Audit staff concluded that the Company should record the current portion of the prepayment in Account 165, but the remaining noncurrent portion should not be accounted for in Account 186. The remaining noncurrent portion of the prepayment should also be accounted for in Account 165.

Recommendations

We recommend NiSource:

4. Require NCSC to reclassify the remaining noncurrent prepayment portion of the finance and accounting transformation servers to Account 165; and

5. Develop policies and procedures to ensure that prepayments are accounted for in Account 165.

3. Accounting for Overfunding of a Single-Employer, Defined Postretirement Benefit Plan

NCSC inappropriately recorded the overfunding of a single employer, defined postretirement life insurance benefit plan in Account 186, Miscellaneous Deferred Debits, for 2009 and 2010. The Company should have recorded the overfunded status in Account 128, Other Special Funds.

Pertinent Guidance

18 C.F.R. § 367.1860 (a) Account 186, Miscellaneous deferred debits, states:

> (a) This account must include all debits not provided for elsewhere, such as miscellaneous work in progress, and unusual or extraordinary expenses, not included in other accounts, that are in the process of amortization and items the proper final disposition of which is uncertain.

18 C.F.R. § 367.1280 (a) Account 128, Other special funds, states:

> (a) This account must include the amount of cash and book cost of investments that have been segregated in special funds for insurance, employee pensions, savings, relief, hospital, and other purposes not provided for elsewhere. This account must also include unrealized holding gains and losses on trading and available-for-sale types of security investments. A separate account with appropriate title, must be kept for each fund.

Docket No. AI07-1-000; To All Jurisdictional Public Utilities and Licensees, Natural Gas Companies, Oil Pipeline and Companies and Centralized Service Companies, states in No. 2:

> 2. Accounts for Recording the Overfunded or Underfunded Status of Postretirement Defined Benefits Plans states in part:
>
> **Question 2A:** What FERC accounts should jurisdictional entities use to record an asset for the overfunded status of one or more employee postretirement benefit plans?
>
> **Response:** Public utilities and licensees, natural gas companies, oil pipeline companies and centralized service companies should use the accounts shown below to record assets for the overfunded status of

their employees postretirement benefit plans. Separate subaccounts should be maintained for each postretirement benefit plan and overfunded plans should not be netted against underfunded plans, consistent with paragraph number 4 of SFAS No. 158.

Jurisdictional Entity	**FERC Accounts**
Public utilities and licensees (Major)	Account 129, Special funds
Public utilities and licensees (Nonmajor)	Account 128, Other special funds, or Account 129, Special funds
Natural gas companies	Account 128, Other special funds
Oil pipeline companies	Account 22, Sinking and other funds
Centralized service companies	
▪ Periods prior to January 1, 2008	Account 124, Other investments, or Account 128, Other special funds
▪ January 1, 2008 and subsequent periods	Account 128, Other special funds

Background

During the testing and verification of service company accounts, audit staff learned that NCSC provided a retiree life insurance benefit for its employees through Prudential Insurance Company (Prudential). An employee's premium is paid by NiSource to Prudential, which provides the benefit. This benefit is available to any active NiSource employee who is 55 years of age and has 10 years of service at retirement. The benefit amount is determined by employee classification (e.g., exempt, nonexempt, nonunion, and by each separate union). A retiree's beneficiary receives life insurance proceeds directly from Prudential.

Aon Hewitt, NiSource's actuary, provides actuarial services at least once annually for NiSource, as ASC 715 (formally SFAS 106) requires, to determine the funded status of NiSource's Postretirement Welfare Plans, for which health care and life insurance benefits are determined separately. Aon Hewitt receives from NiSource the fair value of trust assets on December 31 and determines the obligation associated with the retiree life insurance benefit. The net overfunded status is recorded as a net asset on a respective subsidiary's books, or conversely, the unfunded amount would be recorded as a net liability. NCSC accounted for this overfunding of contributions in Account 186.

Audit staff concluded that the overfunded status of retiree life insurance benefits should not be posted in Account 186. The Company should follow the instructions in Docket No. IA07-1-000 for the overfunded status of one or more employee postretirement benefit plans and use Account 128, Other Special Funds.

Recommendations

We recommend NiSource:

6. Reclassify the overfunded portion of its postretirement life insurance benefit from Account 186 to Account 128 for compliance with Docket No. IA07-1-000; and

7. Properly account for future over- and under-funding of its postretirement life insurance benefit under the requirements in Docket No. IA07-1-000.

4. Improperly Recorded Transferred Employee Benefits

NCSC improperly recorded transferred employee benefits in Account 186, Miscellaneous Deferred Debits, for employees who transferred from Columbia Energy Group (CEG) to NCSC in both 2009 and 2010. The Company should have recorded these benefits in Account 146, Accounts Receivable from Associated Companies, until they were paid.

Pertinent Guidance

18 C.F.R. § 367.1860 (a) Account 186, Miscellaneous deferred debits, states:

> (a) This account must include all debits not provided for elsewhere, such as miscellaneous work in progress, and unusual or extraordinary expenses, not included in other accounts, that are in the process of amortization and items the proper final disposition of which is uncertain.

18 C.F.R. § 367.1460 (a) Account 146, Accounts receivable from associate companies, state:

> (a) This account must include notes and drafts upon which associate companies are liable, and that mature and are expected to be paid in full not later than one year from the date of issue, together with any related interest thereon, and debit balances subject to current settlement in open accounts with associate companies. Items that do not bear a specified due date but that have been carried for more than twelve months and items that are not paid within twelve months from due date must be transferred to account 123, Investment in associate companies (§367.1230).

Background

During review and testing of several select service company accounts, audit staff learned that all NiSource employees are eligible on the date of hire to receive long-term disability (LTD) benefits. Each year, NiSource calculates the LTD estimate based on future medical, dental, and life insurance costs for the next 15 years. Each LTD employee's birthdate is used to determine how much money to accrue per LTD employee per company because employees are eligible to receive these benefits only until age 65. Aon Hewitt, NiSource's actuary, provides the actuarial services for this annual true-up calculation.

NiSource pays an employee's premium for LTD insurance to Prudential. If the employee becomes disabled, Prudential provides LTD coverage and pays benefits directly to the employee.

If an employee transfers to a different affiliate within the NiSource holding company system, the LTD liability balance associated with that employee is also transferred and accounted for in Account 186, Miscellaneous Deferred Debits. In this instance, employees transferred from CEG to NCSC.

Audit staff concluded that the Company's use of Account 186 as an associate company's accounts receivable account was inappropriate. The Company should use Account 146, Accounts Receivable from Associate Companies, for this type of transaction.

Recommendations

We recommend NiSource:

8. Develop policies and procedures to ensure that LTD insurance for transferred employees is properly accounted for in Account 146; and

9. Transfer any remaining LTD amounts for transferred employees to the appropriate account.

Corrective Action

During the audit, NCSC calculated the total deferred debit related to employee transfers and transferred these amounts to Account 146, Accounts Receivable from Associated Companies. NCSC also provided audit staff with journal entries and computer screen images of the completed transactions.

5. FERC-61 Reporting

NiSource did not submit FERC-61, Narrative Description of Service Company Functions, filings for three special-purpose companies between 2006 and 2010, as required under the Commission's regulations.

Pertinent Guidance

18 C.F.R. Part 366.23 (a)(2), FERC Form No. 60, Annual reports of centralized service companies, and FERC-61, Narrative description of service company functions, states:

> (a)(2) FERC–61. Unless otherwise exempted or granted a waiver by Commission rule or order pursuant to §§366.3 and 366.4, every service company in a holding company system, including a special-purpose company (e.g., a fuel supply company or a construction company), that does not file a FERC Form No. 60 shall instead file with the Commission by May 1, 2007 and by May 1 each year thereafter, a narrative description, FERC–61, of the service company's functions during the prior calendar year. In complying with this section, a holding company may make a single filing on behalf of all such service company subsidiaries.

18 C.F.R. Part 366.1, Definitions, codifies the definitions of "goods" and "service" under PUHCA 2005:

> *Goods.* The term "goods" means any goods, equipment (including machinery), materials, supplies, appliances, or similar property (including coal, oil, or steam, but not including electric energy, natural or manufactured gas, or utility assets) which is sold, leased, or furnished, for a charge.
>
> *Service.* The term "service" means any managerial, financial, legal, engineering, purchasing, marketing, auditing, statistical, advertising, publicity, tax, research, or any other service (including supervision or negotiation of construction or of sales), information or data, which is sold or furnished for a charge.

18 C.F.R. Part 367.1, Definitions, codifies the definitions of "centralized service company" and "service company":

> (a)(7) *Centralized service company* means a service company that provides services such as administrative, managerial, financial, accounting, recordkeeping, legal or engineering services, which are sold, furnished, or otherwise provided (typically for a charge) to other companies in the same holding company system. Centralized service companies are different from other service companies that only provide a discrete good or service.
>
> (a)(45) *Service company* means any associate company within a holding company system organized specifically for the purpose of providing non-power goods or services or the sale of goods or construction work to any public utility or any natural gas company, or both, in the same holding company system.

In Order No. 667, the Commission further clarified the distinction between centralized service companies and special-purpose companies:

> "Our adoption of different policies for traditional, centralized service companies compared to special-purpose companies could make the distinction between the two more important than it has been previously. We view the former as performing generally corporate administration functions and the latter as providing generally a single input to utility operations, such as fuel supply, construction, or real estate."[4]

Background

Audit staff reviewed all the entities in NiSource's corporate structure to identify any special-purpose companies. Audit staff discovered that NiSource did not submit a FERC-61 describing non-power goods or services provided by CNS Microwave, Inc., NiSource Insurance Corporation, Inc. (insurance company), and NIPSCO Accounts Receivable Corporation (financing subsidiary) for 2009 or 2010.

CNS Microwave, Inc. leases space on communication towers for its customers, including two of NiSource's interstate pipelines, to install antennas. Also, the company leases ground space in the tower compound for customers to place shelters or cabinets with ground equipment. NiSource Insurance Corporation, Inc. (NICI) is a wholly owned insurance subsidiary of NiSource, Inc. NICI was set up for the purpose of decreasing the reliance on commercial insurance markets to reduce price and coverage volatility, provide stable insurance costs and programs, and reduce the long-term cost of risk for NiSource as a whole.

[4] Order No. 667 at n. 178.

NICI participates as a reinsurer within the NiSource insurance program for NiSource companies, including their interstate pipelines and jurisdictional electric company, on these lines of coverage: Property, Workers' Compensation, General Liability, Auto Liability, Long-Term Disability, and Group Life Insurance. NIPSCO Accounts Receivable Corporation is a wholly owned financing subsidiary that buys trade receivables from NIPSCO and sells them to the Royal Bank of Scotland PLC.

After discussions with NiSource's staff, audit staff concluded that these entities should have made FERC-61 filings to the Commission since they provided goods or services to its public utilities or natural gas companies, or both, within NiSource's corporate structure.

NiSource stated that it inadvertently failed to submit FERC-61 filings for their special-purpose companies due to a lack of formal processes and procedures for identifying them.

Recommendations

We recommend NiSource:

10. Submit FERC-61 filings to the Commission for these special-purpose companies in 2009 and 2010;

11. Develop and implement a process that periodically reviews all corporate entities that require a FERC-61 filing; and

12. Submit copies of any written policies and procedures developed in response to this recommendation to the Commission, within 30 days of the issuance of the final report in this docket.

Corrective Actions

On June 10, 2011, NiSource submitted FERC-61 filings to the Commission for its three special-purpose companies for the calendar years 2006 through 2010 under Docket Nos. HC07-7-000, HC08-7-000, HC09-7-000, HC10-7-000, and HC11-7-000.

6. Untimely Filing for Cash Management Agreement

NiSource did not file changes to its cash management agreement within 10 days of the change in one occurrence during the audit period, as Commission regulations required.

Pertinent Guidance

18 C.F.R. § 141.500 Cash management programs states:

> Public utilities and licensees subject to the provisions of the Commission's Uniform System of Accounts prescribed in part 101 and § 141.1 or § 141.2 of this title that participate in cash management programs must file these agreements with the Commission. The documentation establishing the cash management program and entry into the program must be filed within 10 days of the effective date of the rule or entry into the program. Subsequent changes to the cash management agreement must be filed with the Commission within 10 days of the change.

Background

NiSource operates a cash management program known as "the money pool" to facilitate short-term loans to its affiliates. NiSource's cash management agreement provides the terms and conditions that govern money pool contributions and loans. The cash management agreement contains borrowing and lending terms and conditions, and a listing of companies authorized to participate in the money pool, as well as the handling of excess money pool funds and deficiencies.

NiSource files its cash management agreements with the Commission under Docket No. RM02-14. During the audit, audit staff identified five cash management agreements that NiSource filed. However, when audit staff compared the effective dates of the agreements to the filing dates, it was determined that NiSource filed one cash management agreement 14 days after the effective date and not within the 10 days the Commission requires. NiSource stated that the reason for the late filing was due to an oversight on the part of the company.

Recommendation

13. We recommend NiSource develop and/or strengthen policies and procedures for submitting its cash management agreements and subsequent changes or modifications to ensure compliance with Commission filing requirements.

7. Reporting of Transactions with Associated (Affiliated) Companies

NiSource's electric affiliate, NIPSCO, did not report the required information on page 429, Transactions with Associated (Affiliated) Companies, in the FERC Form No. 1s filed in 2009 and 2010. Similarly, NiSource's gas affiliates, Columbia Gas Transmission Company (TCO) and Columbia Gulf Transmission Company (CGT), did not report the required information on page 358, Transactions with Associated (Affiliated) Companies, in the FERC Form No. 2s filed in 2009 and 2010. Specifically, they did not report the accounts charged or credited for certain non-power goods and services provided for or by affiliates.

Pertinent Guidance

In Order No. 715,[5] the Commission added a new schedule on page 429 of the 2008 FERC Form No. 1 to provide further transparency and improve the detection of cross-subsidization. The new schedule, "Transactions with Associated (Affiliated) Companies," provides information concerning affiliate transactions which includes:

> (1) a description of the good or service charged or credited; (2) the name of the associated (affiliated) company; (3) the USofA account charged or credited; and (4) the amount charged or credited.

In Order No. 710,[6] the Commission added a new schedule on page 358 of the 2008 FERC Form No. 2 to provide further transparency and improve the detection of cross subsidization. The new schedule, "Transactions with Associated (Affiliated) Companies," provides information concerning affiliate transactions which includes:

> (1) a description of the good or service transacted; (2) the name of the associated (affiliated) company; (3) the FERC account charged or credited; and (4) the amount charged or credited.

[5] Revisions to Forms, Statements and Reporting Requirements for Electric Utilities and Licensees, Order No. 715, FERC Stats. & Regs. ¶ 31,277 (2008).

[6] Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines, Order No. 710, FERC Stats. & Regs. ¶ 31,267 (2008).

Background

NiSource's holding company includes one regulated electric utility and two regulated gas pipelines. As part of the audit scope relating to affiliate transactions, audit staff reviewed page 429 of NIPSCO's FERC Form No. 1 and page 358 of TCO and CGT's FERC Form No. 2s.

FERC Form No. 1, page 429, requires electric utilities to disclose the non-power goods and services provided by or for affiliates during the calendar year, including a description of services, an affiliate's name, the accounts used to record the services, and the dollar amount of the services. Specifically, column C requires the company to list the accounts used to record services and prohibits it from using general terms such as "various." For 2009 and 2010, NIPSCO reported the accounts in column C as "various" for multiple charges for both non-power goods provided by and for affiliates. NIPSCO should have either listed the accounts used or footnoted them in the notes following page 429.

FERC Form No. 2, page 358, requires jurisdictional gas pipelines to disclose the non-power goods and services provided by or for affiliates during a calendar year, including a description of services, an affiliate's name, the accounts used to record the services, and the dollar amount of the services. As in the FERC Form No. 1, column C of FERC Form No. 2 requires gas pipelines to list the accounts used to record services and prohibits the company from using general terms such as "various." For both 2009 and 2010, TCO and CGT reported the accounts in column C as "various" for multiple charges for both non-power goods provided by and for affiliates. TCO and CGT should have either listed the accounts used or footnoted the accounts in the notes following page 358.

Recommendations

We recommend NiSource:

14. Strengthen its policies and procedures for submitting data on its FERC Form Nos. 1 and 2 to ensure accurate and complete reporting.

15. Resubmit its 2011 FERC Form Nos. 1 and 2 to correct pages 429 and 358, respectively.

8. Miscellaneous Accounting Classification Errors

NCSC improperly classified certain expenses in the wrong FERC accounts. NCSC should have classified these transactions in the proper accounts as the USofA for centralized service companies prescribed under 18 C.F.R. Part 367.

Pertinent Guidance

18 C.F.R. § 367.2 (a) Companies for which this system of accounts is prescribed, states in part:

(a) Unless otherwise exempted or granted a waiver by Commission rule or order pursuant to §§366.3 and 366.4 of this chapter, this Uniform System of Accounts applies to any centralized service company operating, or organized specifically to operate, within a holding company system for the purpose of providing non-power services to any public utility or any natural gas company, or both, in the same holding company system.

Background

As part of the audit, audit staff tested a sample of transactions to determine if the service company's accounting system was accurately charging the proper amounts to the appropriate FERC accounts. Audit staff identified various income statement items in several accounts. In particular, the errors related to:

Description	Account Used	Proper Account
Charitable Contributions	807.2	426.1
	870	426.1
	921	426.1
	930.2	426.1
Lobbying	930.1, then reclassified to 930.2	426.4
Employee Dues and Memberships	408	921
	923	921
	930.2	921

Description	**Account Used**	**Proper Account**
Meals and Entertainment	923	921
	930.2	921
	932	921
Company Dues and Memberships	870	930.2
	885	930.2
	903	930.2
	921	930.2
	923	930.2
	932	930.2

NiSource should have classified these transactions mentioned above in the proper account as prescribed by the USofA for centralized service companies under 18 C.F.R. Part 367. Audit staff has determined that such misclassifications are immaterial and have no effect on transmission formula rate billings.

Recommendations

We recommend NiSource:

16. Implement accounting policies, processes, and procedures to ensure the types of transactions indentified above are recorded according to Commission regulations; and

17. Post correcting entries to NCSC's accounting records to properly classify all lobbying and political activity charges from the beginning of the audit period to present.

Appendix

NiSource

August 21, 2012

200 Civic Center Drive
Columbus, OH 43215

Bryan K. Craig
Director and Chief Accountant
Division of Audits
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street, NE, RM 5K-13
Washington, DC 20426

RE: Audit of NiSource Inc.
Docket No. FA11-5-000

Dear Mr. Craig:

Thank you for the opportunity to review and comment on the August 6, 2012 Draft Audit Report covering the period January 1, 2009 through December 31, 2010, issued to NiSource Inc. ("NiSource") in the above-referenced docket. NiSource has carefully reviewed audit staff's report addressing NiSource's compliance with the Commission's: 1) cross subsidization restrictions on affiliate transactions; (2) accounting, recordkeeping, and reporting requirements; (3) Uniform System of Accounts (USofA) for centralized service companies; (4) preservation of records requirements for holding companies and service companies; (5) FERC Form No. 60 Annual Report requirements, and the associated public utility and natural gas companies' compliance with the Commission's accounting requirements for transactions with associated companies and the applicable reporting requirements in the FERC Form Nos. 1 and 2. NiSource generally agrees with the findings and recommendations included in the Draft Report. As noted in the detail below, NiSource has already implemented many of the corrective actions recommended therein.

With respect to the specific findings and recommendations, NiSource offers the following response and comment, as requested.

1. Electric Public Utility's Accounting for Billings from the Service Company: NiSource agrees with this finding and recommendation. NiSource will develop and implement procedures to ensure that NiSource Corporate Services Company ("NCSC") and Northern Indiana Public Service Company ("NIPSCO") comply with the Commission's accounting regulations for billings from NCSC. NiSource will provide these procedures to the Division of Audits within 30 days of the issuance of the final audit report in this docket. NiSource has conducted a study from the beginning of the audit period to the present to determine the accuracy of the accounts that NIPSCO used to reallocate and record service company billings specifically for Accounts 163, 870, and 182.3 that NCSC accounted for in Account 923. Based on the study conducted by NiSource and per discussion with FERC audit staff, these items were all charged to the income statement and rolled to retained earnings in a prior calendar period. Thus, FERC correcting entries to NIPSCO's retained earnings for prior year amounts is not deemed necessary based on the materiality of the amounts charged to these accounts in 2009, 2010, and 2011. Going forward, NIPSCO will record the items previously recorded to Accounts 163, 870, and

182.3 to Account 923. NIPSCO calculated the amount that would be refunded under the MISO formula rate recovery mechanism for the billings of amounts for Account 426.1 which was included by NIPSCO above the line. The amount calculated is immaterial (less than $1800 for all three years 2009, 2010 and 2011) and would not materially impact rates. NiSource has provided copies of the refund calculation herein as "Finding 1_Att A_MISO calc 2009.pdf," "Finding 1_Att B_MISO calc 2010.pdf," and "Finding 1_Att C_MISO calc 2011.pdf." In subsequent reporting periods, NIPSCO will record the items previously recorded to Account 923 for donations to 426.1 as recorded by NCSC.

2. **Prepayment for the Use of Finance and Accounting Transformation Servers:** NiSource generally agrees with this finding and recommendation. NCSC recorded a long-term prepaid balance in Account 186, Miscellaneous Deferred Debits, as it interpreted the USofA Part 367, Subpart F-Balance Sheet Chart of Accounts, 18 C.F.R. § 367.1650, Account 165 Prepayments, to be designated only for "Current and Accrued Assets" as noted under Subpart F. For regulatory accounting, NCSC did reclassify the entire non-current prepayment balance for the use of Finance and Accounting transformation servers at 12/31/11 from Account 186 to Account 165 as noted in the 2011 FERC Form No. 60, page 110, Line No. 4 footnote. The reclassification entry completed at December 31, 2011 is provided herein as "Finding 2_Att. A_165 Transformation.pdf." The prepayment for the use of Finance and Accounting transformation servers will be fully amortized as of June 30, 2015.

3. **Accounting for Overfunding of a Single-Employer, Defined Postretirement Benefit Plan:** NiSource generally agrees with this finding and recommendation. NCSC had recorded its overfunding of its defined postretirement benefit in Account 186, Miscellaneous Deferred Debits, which is a noncurrent asset account in compliance with ASC 715-20, *Compensation-Retirement Benefits, Defined Benefit Plans.* Further, per 18 C.F.R. § 367.1280(b), "amounts deposited with a trustee under the terms of an irrevocable trust agreement for pensions or other employee benefits must not be included in Account 128." Therefore, based on the Section 367.128(b), NCSC felt it was in compliance with Title 18 C.F.R. Part 367 – Uniform System of Accounts for Centralized Service Companies as NCSC funds its postretirement benefits through an irrevocable trust agreement. The Commission's Chief Accountant issued a guidance letter in Docket No. AI07-1-1000 in March 2007, which states that centralized service companies should use Account 128 to record assets for the overfunded status of their employee postretirement benefit plans. Based on audit staff's explanation that the guidance letter issued in Docket No. AI07-1-1000 supersedes 18 C.F.R. § 367.1280(b), NCSC made a regulatory accounting reclassification of the overfunding amount in Account 186 to Account 128 to be in full compliance with the guidance issued in Docket No. AI07-1-000. The reclassification entry completed at December 31, 2011 is provided herein as "Finding 3_Att. A_128 Overfunding.pdf." Further, NCSC's 2011 FERC Form No. 60, page 110, Line 5, shows the 186 balance to be $0 at December 31, 2011. At December 31, 2011, and thereafter, NCSC is properly accounting for future over- and underfunding of its postretirement life insurance benefit under the guidance issued in Docket No. AI07-1-000.

4. **Improperly Recorded Transferred Employee Benefits:** NiSource agrees with this finding and recommendation. As noted in the Corrective Actions listed on page 23 of the Audit Report, NiSource has provided audit staff with journal entries and screen images of the

completed transactions. In addition, NiSource's 2011 FERC Form No. 60, page 110, Line 5, shows the 186 balance to be $0 at December 31, 2011. NCSC did develop a new policy and procedure in December of 2011 to ensure that LTD insurance for transferred employees is properly accounted for in Account 146. A copy of the written policies and procedures developed in response to this recommendation is provided herein as "Finding 4_Att. A_LTD Benefits Policy.doc."

5. **FERC-61 Reporting for Special Purpose Companies:** NiSource agrees with this finding and recommendation. As noted in the Corrective Actions listed on page 26 of the Audit Report, NiSource has submitted the FERC-61 filings required for the years 2006 – 2009 for its special-purpose service companies. NiSource has updated its policies and procedures to now include the filing of FERC-61 reports in its regulatory compliance program so that these documents are filed in a timely manner. Copies of the written policies and procedures developed in response to this recommendation are included herein as "Finding 5_Att. A_FERC Holding Co. Policy.pdf" and "Finding 5_Att. B_FERC Service Co. Policy.pdf".

6. **Untimely Filing of Cash Management Programs:** NiSource agrees with this finding and recommendation. NiSource submitted one cash management agreement within 10 business days (14 calendar days), and not within the 10 calendar days as required by the Commission's regulations (18 C.F.R. § 141.500). NiSource has discussed its process internally and commits to strengthen its policies and procedures to ensure that all employees involved in the preparation and filing of cash management agreements are aware of the filing requirements. There have been no other instances of late filings.

7. **Reporting of Transactions with Affiliated Companies:** NiSource agrees with this finding and recommendation. NiSource will resubmit its 2011 FERC Form No. 2 for Columbia Gas Transmission, LLC, and Columbia Gulf Transmission Company to correct page 358 by replacing the term "various" with a listing of accounts used to record the services. Filings will be resubmitted by the end of the third quarter 2012. NIPSCO strengthened its procedures during 2011 and filed the 2011 FERC Form No. 1, page 429, properly by providing a listing of accounts used to record services rather than "various" as done in its 2009 and 2010 filings. Included herein is attachment "Finding 7_Att A_Form 1.pdf" which is a copy of NIPSCO's 2011, Form 1, page 429. NiSource's interstate pipelines have completed their documentation of compliance procedures for each of their Form No. 2 pages. Included herein is attachment "Finding 7_Att B_Form 2 p. 358 procedures.pdf" which is a copy of the NiSource's compliance procedures specifically for p. 358 of Form No. 2. Upon request, NiSource will make copies of all compliance procedures for all pages of its Form No. 2 available to FERC.

8. **Miscellaneous FERC Account Classification Errors:** NiSource agrees with this finding and recommendation. Starting in the third quarter of 2011, NCSC strengthened its policies and procedures for ensuring that expenses were in the proper FERC accounts. A copy of the policy implemented by NCSC is included herein as "Finding 8_Att. A_FERC Classification Policy.docx." In compliance with its policy, NCSC is performing an analysis and making reclassification entries on a quarterly basis to ensure proper recording to FERC accounts. The quarterly reclassification entries made to properly record to FERC accounts are included herein as "Finding 8_Att. B_Q3 2011 FERC Reclass.pdf," "Finding 8_Att. C_Q4 2011 FERC

Reclass.pdf," "Finding 8_Att. D_Q1 2012 FERC Reclass.pdf," and "Finding 8_Att. E_Q2 2012 FERC Reclass.pdf." Amounts recorded for lobbying and political activities for the audit period were immaterial in nature ($748 in 2009 and $10,436 in 2010), have rolled to retained earnings in a prior calendar period, and thus NiSource deems prior period entries unnecessary.

Until all corrective actions have been implemented, NiSource will make the recommended quarterly progress reports no later than 30 days after the end of each calendar quarter.

NiSource appreciates the professionalism and transparency of audit staff assigned to this audit. NiSource takes its compliance obligations very seriously, and we continually strive to improve and enhance our regulatory compliance efforts. Should you have any questions regarding this response, please do not hesitate to contact Susanne M. Taylor, Controller of NiSource Corporate Services Company, at 614-460-4686. Thank you for your time and attention in this matter.

Sincerely,

Stephen P. Smith
Executive Vice President and Chief Financial Officer

cc: Gerald Williams

Attachments Enclosed on CD:
Finding 1 _Att A_MISO calc 2009.pdf
Finding 1_Att B_MISO calc 2010.pdf
Finding 1_Att C_MISO calc 2011.pdf
Finding 2_Att. A_165 Transformation.pdf
Finding 3_Att. A_128 Overfunding.pdf
Finding 4_Att. A_LTD Benefits Policy.doc
Finding 5_Att. A_FERC Holding Co. Policy.pdf
Finding 5_Att. B_FERC Service Co. Policy.pdf
Finding 7_Att A_Form 1.pdf
Finding 7_Att B_Form 2 p. 358 procedures.pdf
Finding 8_Att. A_FERC Classification Policy.docx
Finding 8_Att. B_Q3 2011 FERC Reclass.pdf
Finding 8_Att. C_Q4 2011 FERC Reclass.pdf
Finding 8_Att. D_Q1 2012 FERC Reclass.pdf
Finding 8_Att. E_Q2 2012 FERC Reclass.pdf

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

65. Refer to Columbia's response to Commission Staffs First Request for Information ("Staffs First Request"), Item 26. Provide the following:

a. The reasons for the increase in the cash account balance between November 2012 and December 2012 of $1,143,456 ($1,509,717 - $366,261).

b. The reasons for the decrease in the cash account balance between December 2012 and January 2013 of $1,205,729 ($1,509,717 - $303,988).

Response:

(a.) Columbia's cash balance increased in December primarily due to the receipt of a customer advance for construction in the amount of $685,971.

(b.) Columbia's cash balance decreased the following month to fund Columbia's normal operating needs.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

66. Refer to the response to Staffs First Request, Item 30. Provide the reasons for the increase in Administrative & General Expenses in the amount of $1,222,779 ($15,901,387 - $14,678,608) or approximately 8.3 percent, from calendar year 2012 to the base period ended August 31, 2013.

Response:

The increase in Administrative & General Expenses from calendar year 2012 to the base period is primarily due to increases in pension expense of $944,438, management fee of $476,267 and labor of $83,926, partially offset by a decrease in other benefits expenses of $297,020.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

67. Refer to the response to Staffs First Request, Item 33. Confirm that for calendar years 2008 through 2012 Columbia's actual payroll was, on average, roughly 3.6 percent below its budgeted level.

Response:

Columbia's actual payroll is, on average, approximately 3.6 percent below the budgeted level for the years 2008 through 2012.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

68. Refer to the response to Staffs First Request, Item 35. Provide the following:

a. The same information for calendar years 2009 and 2010.

b. An explanation of how the "Annualized Amount" for the Exempt, Nonexempt (nonunion) and Union categories are calculated along with any related spreadsheets, workpapers, and supporting calculations.

Response:

To obtain the annualized rate, the hourly value of each employee's increase was multiplied by 2,080 hours for the hourly employees or by 12 for the monthly compensated employees. The employee's annualized rate was then summed by union, exempt and non-exempt non-union status.

Please see the tables below for 2009 and 2010.

2009

	Exempt	Nonexempt (nonunion)	Union
Annualized Amount	$17,573	$21,886	$200,270
Percent Increase	0%*	3.00%	3.50%
Effective Date	NA	March 1, 2009	December 1, 2009

* In 2009, most exempt employees received a 2 percent lump sum payment only with no increase to base. However, front line supervisors were eligible for an increase of 3 percent. The annualized value is reflecting just those front line supervisors that received an increase on March 1, 2009.

2010

	Exempt	Nonexempt (nonunion)	Union
Annualized Amount	$54,641	$26,770	$173,876
Percent Increase	3.50%	3.50%	3.00%
Effective Date	June 1, 2010	June 1, 2010	December 1, 2010

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

69. Refer to the response to Staffs First Request, Item 36. Provide the allocation methodology used to allocate costs associated with employees of NiSource Services to Columbia.

Response:

Employees of NiSource Corporate Services Company allocate to Columbia using an allocation basis or bases appropriate for the NiSource companies for which they have responsibility. Please refer to the direct testimony of Columbia witness Taylor for an explanation of the Bases of Allocation.

**COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013**

70. Refer to the response to Staffs First Request, Item 41. Provide a description of the Profit Sharing fringe benefit, the classes of employees who participate in the Profit Sharing program and how the amount to be distributed is calculated.

Response:

a. Please refer to the attachment hereto for Sections 3.06 and 3.07 of the NiSource Retirement Savings Plan for a description of profit sharing. Employee classifications eligible for profit sharing are exempt, non-exempt non-union, and Columbia union.

NISOURCE INC. RETIREMENT SAVINGS PLAN

Amended and Restated Effective as of January 1, 2013

December 2012

Section 3.06 Profit Sharing Contributions and Next Gen Employer Contributions. Except as provided in subparagraph C below, for each Plan Year, the Employer may contribute to the Trust amounts determined in its discretion. Such contributions will be in the form of "Profit Sharing Contributions" (previously designated "Profit Participation Contributions" in the Plan 2006 Restatement) as described in subparagraph A and B below. In addition, as provided in subparagraph C below, the Employer shall make the "Next Gen Employer Contribution" described therein.

A. Amount of Profit Sharing Contribution. The Profit Sharing Contribution made for a Plan Year shall be a stated percentage of the Compensation of the Participants entitled to receive allocations of such Profit Sharing Contribution for such Plan Year in accordance with the eligibility and allocation provisions set forth in Plan Section 3.07. The applicable percentage for each Plan Year shall be designated by the Committee, in its discretion exercised on a non–discriminatory basis, no later than the last day of the first quarter of the Plan Year following the Plan Year for which such percentage is applicable. For purposes of this Section 3.06A, Compensation for a Plan Year shall be defined as determined under the Annual Incentive Plan of an Employer in effect for such Plan Year, reduced by any amounts deferred to a nonqualified plan maintained by an Employer, as described in Section 1.19B(i) of the Plan. In allocating a Profit Sharing Contribution to a Participant's Account, the Plan Administrator, subject to Section 11.01, shall take into account only Compensation paid to the Employee during the portion of the Plan Year during which the Employee was a Participant. In no event shall a Profit Sharing Contribution be made with respect to any Participant for any Plan Year to the extent such Profit Sharing Contribution would cause the limitations of Code Section 415 to be exceeded for such Participant for such Plan Year.

B. Prior Profit Sharing Contributions. Prior to January 1, 2002, the Employer contributed other amounts as Profit Sharing Contributions to Participants as described in the Plan 2006 Restatement. The provisions relating to these "Prior Profit Sharing Contributions" including rules and conditions for eligibility, allocation, vesting, forfeitures, and investments, apply as set forth in the Plan 2006 Restatement. The Plan Administrator and/or Trustee shall maintain a "Prior Profit Sharing Contributions Account" to the extent that such contributions require a subaccount that is separate from the Profit Sharing Account.

C. Next Gen Employer Contributions. Notwithstanding the foregoing, effective as of January 1, 2010, the Employer shall contribute each pay period to the Account of each Participant who is both an Eligible Employee and a Next Gen Employee at such time an amount equal to 3% of such Participant's total Compensation for that pay period (as defined in Section 1.19B(ii)). Such contribution shall be a "Next Gen Employer Contribution." This amount shall be payable to applicable Participants regardless of whether such Participants have elected to make Pre-Tax Contributions, Roth Contributions or any other elective deferrals to the Plan and regardless of the Participants' status as of the end of the Plan Year. As provided in Section 3.07B, this Next Gen Employer Contribution shall be allocated to the Company Stock Fund and shall be 100% vested and nonforfeitable at all times. Eligibility for a Next Gen Employer Contribution under this subparagraph C shall not preclude eligibility for any other Profit Sharing Contribution under the terms contained herein.

Section 3.07 Profit Sharing and Next Gen Employer Contribution Allocation / Investment.

A. Eligibility and Accrual. Each Eligible Employee meeting the allocation requirements of this Section is entitled to participate in Profit Sharing Contributions; provided, however, that if an Eligible Employee is subject to a collective bargaining agreement, such agreement must provide that the Employee is eligible for Profit Sharing Contributions. For Profit Sharing Contributions other than those Next Gen Employer Contributions described in Section 3.06C, the Plan Administrator shall determine the accrual of a Profit Sharing Participant's benefit on the basis of the Plan Year. Although contributions may be made at other times (and therefore credited to Accounts at such other times), the Participant's status as of the end of the Plan Year for which the contribution is made shall determine his entitlement to share in an allocation of such contribution, regardless of when credited to his Account. For Profit Sharing Contributions other than Next Gen Employer Contributions described in Section 3.06C, the Plan Administrator shall not allocate any portion of a Profit Sharing Contribution for a Plan Year to the Account of any Participant, if such Participant is not employed by the Employer on the last day of that Plan Year (for a reason other than retirement, Disability, or death). The Plan shall suspend the accrual requirement described herein if the Plan fails to satisfy the requirements of Code Section 410(b). Notwithstanding any other provision to the contrary, a Profit Sharing Contribution or Next Gen Employer Contribution shall not be allocated to a Participant's Account to the extent the contribution would exceed the Participant's "Maximum Permissible Amount" under Section 7.02.

B. Allocation, Investment and Vesting. Subject to Article XI and except as provided for contributions described under section 3.06C, the Plan Administrator shall allocate and credit to the Account of each Participant who satisfies the conditions of Section 3.07A a percentage of the annual Profit Sharing Contribution in the ratio that the sum of the Participant's total Compensation for the Plan Year bears to the sum of all such Participants' total Compensation for the Plan Year. All Profit Sharing Contributions, including Next Gen Employer Contributions under Section 3.06C, shall be allocated to the Company Stock Fund, pursuant to Section 8.07 and 8.08. All Profit Sharing Contributions, including Next Gen Employer Contributions under Section 3.06C, shall be 100% vested and nonforfeitable at all times.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

71. Refer to the response to Staffs First Request, Item 48, Attachment A. Provide the following:

a. A general explanation of why the current year provision varied so widely over the years 2010-2012.

b. A breakdown of the annual Charges to Reserve Accounts (accounts charged off) by customer class.

c. An explanation of how the annual amounts are determined for Credits to Reserve Accounts.

d. An explanation of how the annual amounts are determined for the current year provision.

e. The amount of uncollectible accounts that were expensed in each of the three years.

Response:

a. The primary driver of the variances in the current year provision for the years 2010-2012 is the actual net charge-offs for low pressure accounts (residential, commercial and industrial). In 2010, Columbia experienced net charge-offs of approximately $244,000. In 2011, the net charge-offs were approximately $631,000. In 2012, the net charge-offs were approximately $229,000.

b. Charge-offs are available by low pressure residential, commercial and industrial and by high pressure commercial and industrial. Charge-offs for 2010-2012 are:

Year	Low Pressure	High Pressure	Amount
2010	$ 971,914		$ 971,914
2011	$ 1,174,256	$ 144	$ 1,174,400
2012	$ 577,904		$ 577,904

c. The amounts identified as Credits to Reserve Accounts reflect recoveries from customers after their accounts were charged off.

d. The current year provision (expense) includes the provision for low pressure accounts (residential, commercial and industrial) and high pressure accounts (commercial and industrial).

The current year provision (expense) for low pressure accounts reflects the difference between the prior year-end uncollectible accounts balance and the sum of the current year net charge-offs and the expected current year-end uncollectible accounts balance. To determine the expected current year-end uncollectible accounts balance, Columbia takes into consideration that it charges off accounts receivable in excess of 120 days outstanding from the initial billing date. Therefore, the year-end uncollectible accounts balance needs to reflect the portion of receivables recorded for September through December that will not be collected. The actual net charge-offs for the twelve months ended December are divided by the residential revenue for the twelve months ended August to determine the most recent experience factor. This experience factor is multiplied by the September through December revenues to provide the needed year-end uncollectible account balance.

The current year provision (expense) for high pressure commercial and industrial accounts is determined based on a review of each specific delinquent high pressure commercial and industrial account by Columbia representatives from the Finance, Revenue Recovery and Gas Transportation departments.

e. Please see the table below for total uncollectible accounts expense recorded in 2010, 2011, and 2012.

	2010	2011	2012
Low Pressure (Non-Gas)	(92,000)	(632,570)	78,000
Low Pressure (Gas)	828,188	620,377	45,729
High Pressure	(4,048)	43,792	(4,932)
EAP (Tracker)	498,140	562,580	415,673
Total	1,232,290	596,190	536,482

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

72. Refer to the response to Staffs First Request, Item 49. Explain whether any of the advertising services provided by Sheehy & Associates in calendar year 2012 were associated with political, promotional, and institutional advertising as defined by 807 KAR 5:016, Section 4.

Response:

Most services provided by Sheehy & Associates are for public awareness or educational campaigns. Aside from those campaigns, advertising services provided by Sheehy & Associates are creative design services related to community support and totaled $313.75 in 2012. Community support primarily encompasses event sponsorships of worthwhile organizations.

KY PSC Case No. 2013-00167
Response to Staff's Data Request Set Two No. 073
Respondent: S. Mark Katko and Brooke E. Leslie

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

73. Refer to the response to Staffs First Request, Item 54, Attachment C. Included in the projected rate case expenses is $300,000 for "Legal Fees." Explain the derivation of this amount given that different filings in this proceeding have identified Mr. Seiple and Ms. Leslie, respectively, as Assistant General Counsel and Senior Counsel of "Columbia Gas of Kentucky."

Response:

Columbia is using the assistance of outside counsel for strategy and support in this case.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S SECOND REQUEST FOR INFORMATION
DATED JULY 19, 2013

74. Refer to the response to Staffs First Request, Item 55.b, which shows that, of the total of $13,449,161 billed Columbia by NiSource Services in calendar year 2012, $8,562,526 was recorded in Account 923, Outside Services. Explain in detail why nearly two-thirds of what NiSource Services billed Columbia could not, apparently, be recorded in a more function-specific or service-specific account.

Response:

Columbia records costs billed via NiSource Corporate Services Company (NCSC) to Account 923, Outside Services, for fees and expenses of professional consultants and administrative and general services which are not applicable to a particular operating or customer service functions, or to other specific accounts such as capital, etc., which is in compliance with FERC Order 684.