- Group Rating Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Atmos Energy Corporation

Full Rating Report

Ratings

Long-Term IDR	A–
Short-Term IDR	F2
Senior Unsecured	A
Commercial Paper	F2

IDR – Issuer Default Rating.

Rating Outlook

Long-Term IDR	Stable

Financial Summary

Atmos Energy Corporation
(Sept. 30 Year End)

($ Mil.)	LTM 12/31/15	2015
Adjusted Revenue	3,789	4,142
Operating EBITDAR	951	939
Cash Flow from Operations	880	837
Total Adjusted Debt	3,474	3,177
Total Capitalization	6,490	6,108
Capex/ Depreciation (%)	361.9	354.5
FFO Fixed-Charge Coverage (x)	6.6	6.4
FFO-Adjusted Leverage (x)	3.5	3.3
Total Adjusted Debt/EBITDAR (x)	3.7	3.4

Related Research

Atmos Energy Corporation – Ratings Navigator (September 2015)

Fitch Upgrades Atmos Energy to 'A–'; Outlook Stable (July 2015)

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Key Rating Drivers

Constructive Regulatory Environment: Atmos Energy Corporation (Atmos) operates in constructive regulatory jurisdictions that allow Atmos to recover its capex in a timely manner, reducing regulatory lag and adding stability to earnings and cash flow. The local distribution company (LDC) business has several supportive regulatory mechanisms, including annual rate-making, weather normalization, and purchased gas cost adjustments. Atmos' Texas intrastate pipeline system has an authorized return on equity (ROE) of 11.8% and annual gas reliability infrastructure program (GRIP) filings.

Large, Geographically Diverse Operations in High-Growth Markets: The ratings are further supported by Atmos' large and geographically diverse regulated operations with exposure to above-average service territories. More than 60% of operating income is from operations in Texas, which remains a high-growth market benefitting from population and employment growth. Atmos' LDC utility business operates in eight states, although roughly 78% of its rate base is located in Texas, Louisiana, and Mississippi. Atmos also benefits from its regulated Texas intrastate pipeline system and associated storage assets, which provide access from several natural gas basins to three of the major Texas hubs.

Capex Growth and Timely Recovery: Capex is expected to total nearly $1.1 billion in the fiscal year ended Sept. 30, 2016, with safety and reliability capex estimated to account for 80%–85% of the total. Fitch expects system improvement programs to continue to drive growth and for total capex to average close to $1.2 billion per year over the 2016–2018 period. Regulatory mechanisms allow for timely recovery of capital spending, with greater than 90% of annual capex earning a return within six months of test year end (half of that with no lag) and only 4% subject to general rate case filings resulting in more than a 12-month lag.

Declining Average Cost of Debt: Fitch expects Atmos' average cost of long-term debt, currently at 5.7%, to continue to decline as higher-coupon notes mature and are replaced with lower-coupon notes. Atmos' next long-term debt maturity is in June 2017, when $250 million of 6.35% notes mature, followed in March 2019 with $450 million of 8.5% notes. Atmos has forward-starting interest rate swaps on the replacement of both notes, effectively fixing Treasury yields at 3.367% and 3.782%, respectively. Excluding these relatively high-coupon notes, Atmos' long-term cost of debt is 4.9%; coverage metrics should benefit accordingly.

Rating Sensitivities

Positive Rating Action: Near-term positive rating actions are unlikely. However, achieving adjusted debt/EBITDAR leverage of less than 3.0x and FFO adjusted leverage of less than 3.25x on a sustainable basis could lead to another positive rating action.

Negative Rating Action: A negative rating action could result from a sustained increase of adjusted debt/EBITDAR leverage to greater than 3.75x and FFO adjusted leverage to greater than 4.0x. A negative rating action could also result from an unexpected adverse regulatory decision, expansion of non-regulated business activities, or failure to maintain the current capital structure while pursuing a relatively elevated capex program.

Financial Overview

Liquidity and Debt Structure

Liquidity is adequate, supported by sufficient availability under Atmos' $1.25 billion commercial paper (CP) program, which is backed up by an equal-sized revolving credit facility. The facility has an accordion feature that allows for an increase in borrowing capacity to $1.5 billion. The five-year facility matures Sept. 25, 2020. As of Dec. 31, 2015, there was $763 million of CP outstanding, leaving $487 million of availability under the facility.

In addition, Atmos maintains a $25 million facility that matures on April 1 each year and a $10 million facility that matures on Sept. 30 each year. These facilities are used primarily to issue letters of credit.

Atmos Energy Holdings, Inc. (AEH) is a wholly owned subsidiary that houses Atmos' nonregulated operations. AEH's subsidiary, Atmos Energy Marketing, LLC (AEM), has a committed $15 million credit facility and an uncommitted $25 million credit facility. Both are 364-day bilateral facilities, with the $15 million facility maturing on Sept. 30 each year and the $25 million facility maturing on Dec. 31 each year. These facilities are used primarily to issue letters of credit.

There is also a $500 million intercompany facility, which primarily enables the regulated operations to borrow directly from AEH, and indirectly from AEM, thus allowing for an efficient use of internal cash to fund operations.

Atmos keeps a modest amount of cash on hand, and none of it is restricted.

Debt maturities are manageable. Atmos has a very long-dated maturity profile that is more conservative than that of most other utilities. (Note: Atmos' fiscal year ends Sept. 30.)

Related Criteria

Recovery Ratings and Notching Criteria for Utilities (March 2016)

Corporate Rating Methodology — Including Short-Term Ratings and Parent and Subsidiary Linkage (August 2015)

Parent and Subsidiary Rating Linkage (August 2015)

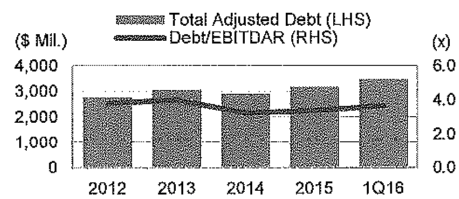
Rating U.S. Utilities, Power and Gas Companies (Sector Credit Factors) (March 2014)

Debt Maturities and Liquidity

($ Mil., As of Dec. 31, 2015)	
2016	—
2017	250
2018	—
2019	450
Thereafter	1,760
Cash and Cash Equivalents	79
Undrawn Committed Facilities	487

Source: Company data, Fitch.

Total Debt and Leverage

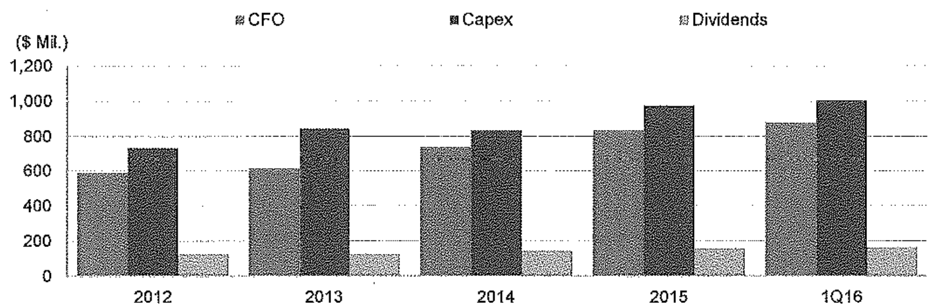


Source: Company data, Fitch.

Cash Flow Analysis

Atmos has a balanced capital structure, with a debt/capitalization ratio that has typically been at the lower end of management's target of 50%–55%. Due to its large capex program, Atmos will be moderately FCF negative through 2018. Fitch expects future funding needs to be financed by a roughly 50/50 mix of debt and equity to maintain the current capital structure. (Note: Atmos' fiscal year ends Sept. 30.)

CFO and Cash Use



Source: Company data, Fitch.

Peer and Sector Analysis

Peer Group

Issuer	Country
A	
Southern California Gas Co.	U.S.
A–	
Southwest Gas Corporation	U.S.
BBB+	
AGL Resources, Inc.	U.S.

Issuer Rating History

Date	LT IDR (FC)	Outlook/ Watch
Sept. 30, 2015	A–	Stable
July 1, 2015	A–	Stable
Oct. 1, 2014	BBB+	Positive
May 21, 2014	BBB+	Positive
April 29, 2013	BBB+	Stable
April 30, 2012	BBB+	Stable
June 2, 2011	BBB+	Stable
June 21, 2010	BBB	Positive
March 23, 2009	BBB	Stable
Aug. 7, 2008	BBB	Stable
June 7, 2007	BBB	Stable
Jan. 13, 2006	BBB	Stable
Dec. 6, 2005	BBB+	Negative
Sept. 30, 2004	BBB+	Negative
June 17, 2004	A–	RWN
Feb. 27, 2004	A–	Stable
April 11, 2001	A–	Stable
April 18, 2000	A–	RWN
Nov. 9, 1999	A–	—

LT IDR – Long-Term Issuer Default Rating. FC – Foreign currency. RWN – Rating Watch Negative.
Source: Fitch.

Peer Group Analysis

($ Mil.)	Atmos Energy Corporation	Southern California Gas Co.	Southwest Gas Corporation	AGL Resources, Inc.
As of	12/31/15	12/31/15	12/31/15	12/31/15
IDR	A–	A	A–	BBB+
Outlook	Rating Outlook Stable	Rating Outlook Stable	Rating Outlook Stable	Rating Watch Positive
Fundamental Ratios (x)				
Operating EBITDAR/ (Gross Interest Expense + Rents)	6.30	8.21	7.41	5.81
FFO Fixed-Charge Coverage	6.58	5.21	6.95	5.71
Total Adjusted Debt/Operating EBITDAR	3.65	2.48	2.85	3.98
FFO/Total Adjusted Debt (%)	28.6	25.8	32.9	24.7
FFO-Adjusted Leverage	3.50	3.88	3.04	4.05
Common Dividend Payout (%)	51.3	11.9	53.2	69.1
Internal Cash/Capex (%)	67.4	38.7	77.5	73.5
Capex/Depreciation (%)	361.9	293.3	180.7	258.7
Return on Equity (%)	9.8	13.3	8.7	9.0
Financial Information				
Revenue	3,789	3,489	2,464	3,941
Revenue Growth (%)	(23.4)	(9.5)	16.1	(26.8)
EBITDA	918	1,069	559	1,201
Operating EBITDA Margin (%)	24.2	30.6	22.7	30.5
FCF	(290)	(523)	(15)	92
Total Adjusted Debt with Equity Credit	3,474	2,752	1,604	4,898
Cash and Cash Equivalents	79	58	36	19
Funds Flow from Operations	842	573	452	999
Capex	(1,006)	(1,352)	(488)	(1,027)

IDR – Issuer Default Rating.
Source: Company data, Fitch.

Key Rating Issues

Constructive Regulatory Environment

Atmos benefits from a relatively constructive regulatory environment. Atmos' LDC utility operations are able to employ several cost-recovery and cash flow-stabilizing mechanisms, including annual ratemaking, weather normalization, and purchased gas cost adjustments, which reduce regulatory lag and add a level of predictability to earnings and cash flows. The 5,600-mile Texas intrastate pipeline system has an authorized ROE of 11.8% and benefits from annual GRIP filings, which allow for the recovery of capex in a timely manner.

The overwhelming majority of the distribution segment's operating income is subject to annual ratemaking without filing a formal rate case. Roughly 97% of the distribution segment's operating income is covered under weather normalization mechanisms, and Atmos has purchased gas cost adjustment mechanisms that provide a dollar-for-dollar offset of increases or decreases in purchased gas costs in all its distribution service territories. In addition, 76% of operating income is from jurisdictions with trackers that cover the gas portion of customer bad-debt expense.

Obtaining these aforementioned regulatory mechanisms throughout Atmos' multistate service territory has made the distribution segment's operating income and cash flows more predictable, while improving system reliability and safety. These efforts have also led to strong organic growth opportunities, resulting in a greater share of operating income and cash flows from Atmos' stable, low-risk operations.

Large, Geographically Diverse Operations in High-Growth Markets

The ratings are further supported by Atmos' large and geographically diverse regulated operations, with LDC utility businesses in eight states, although roughly 78% of its rate base is located in Texas, Louisiana, and Mississippi. Atmos also benefits from its regulated Texas intrastate pipeline system and associated storage assets, which provide access from several natural gas basins to three of the major Texas hubs.

More than 60% of operating income is from operations in Texas, which remains a high-growth market benefitting from population and employment growth. Despite a dramatic decrease in oil prices that occurred in the second half of 2014, the Texas economy has remained vibrant, led by strong growth in the Dallas-Fort Worth area, which is Atmos' major service territory and focus for capex growth. Atmos does not operate in Houston or elsewhere in southeast Texas, which has been more negatively impacted by the low commodity prices.

Capex Growth and Timely Recovery

Capex was $975 million in the fiscal year ended Sept. 30, 2015. For fiscal year 2016, capex is expected to total nearly $1.1 billion, with safety and reliability capex estimated to account for 80%–85% of the total. Replacement of aging pipe and other system improvement programs should continue to drive growth well into the future. Fitch expects total capex to average close to $1.2 billion per year over the 2016–2018 period.

Regulatory mechanisms allow for timely recovery of capital spending. Greater than 90% of capex starts earning a return on invested capital within six months of test year end, with half of that experiencing no lag. About 5% of capex is exposed to a lag of seven to 12 months, and only 4% of capex is subject to general rate case filings resulting in more than a 12-month lag.

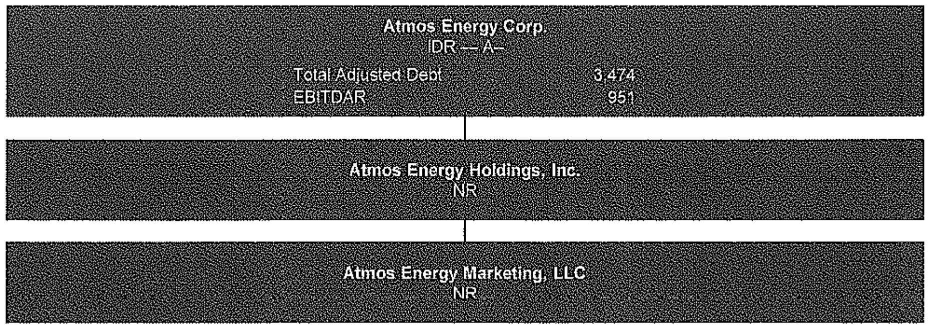
Non-Regulated and Market-Sensitive Operations

Slightly offsetting these strengths are the company's non-regulated operations, which include gas supply management, marketing, and gathering and storage services that are mainly conducted at the company's AEH subsidiary. These operations have a higher level of business risk than the company's regulated gas distribution and pipeline operations, in the form of greater earnings volatility and commodity exposure. AEH's physical hedges and few net open positions help mitigate these concerns. Over the past three fiscal years, non-regulated operations have contributed an average of 7% of consolidated net income, while requiring only a nominal amount of capex to support them.

Organizational Structure

Organizational Structure — Atmos Energy Corporation

($ Mil., As of Dec. 31, 2015)



IDR – Issuer Default Rating. NR – Not rated.
Source: Company filings, Fitch.

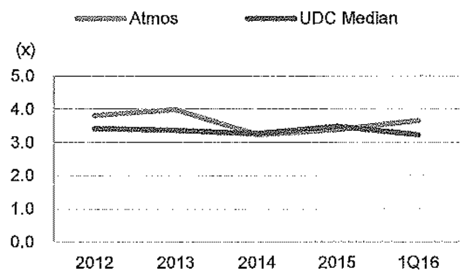
Key Metrics

Note: Atmos' fiscal year ends Sept. 30.

Definitions

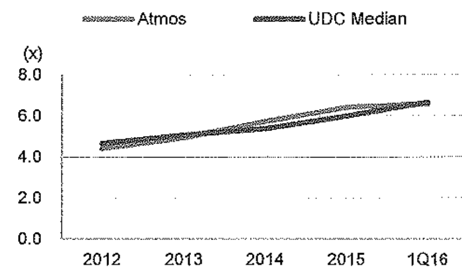
- Total Adjusted Debt/Op. EBITDAR: Total balance sheet adjusted for equity credit and off-balance sheet debt divided by operating EBITDAR.
- FFO Fixed-Charge Coverage: FFO plus gross interest minus interest received plus preferred dividends plus rental payments divided by gross interest plus preferred dividends plus rental payments.
- FFO-Adjusted Leverage: Gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock divided by FFO plus gross interest paid plus preferred dividends plus rental expense.

Total Adjusted Debt/Op. EBITDAR



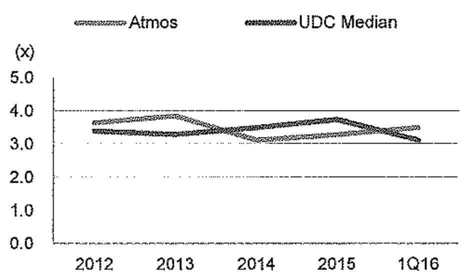
UDC – Utility distribution company.
Source: Company data, Fitch.

FFO Fixed-Charge Coverage



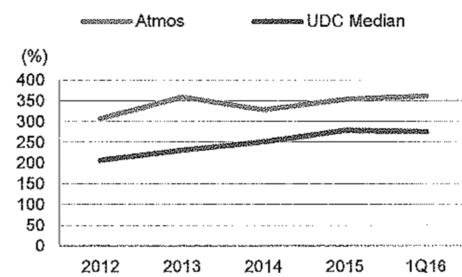
UDC – Utility distribution company.
Source: Company data, Fitch.

FFO-Adjusted Leverage



UDC – Utility distribution company.
Source: Company data, Fitch.

Capex/Depreciation



UDC – Utility distribution company.
Source: Company data, Fitch.

Company Profile

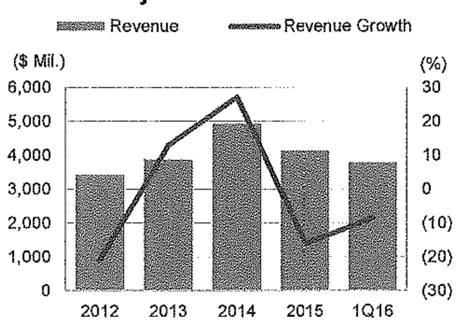
Atmos is a divisionally structured utility that operates in three business segments: regulated gas distribution through LDCs, regulated pipelines through its Texas intrastate pipeline system, and non-regulated gas marketing and storage through subsidiary AEH's operations. Atmos serves more than 3 million residential, commercial, and industrial customers across Texas, Louisiana, Mississippi, Kentucky, Tennessee, Kansas, Colorado and Virginia.

The absence of a holding company is a less common structure for a utility, but it does not present any inordinate credit risks. As a divisionally structured utility, all financing is done at the parent level, and the related costs are allocated to the utility divisions and passed through in tariffs as part of the regulator-approved rate of return. All debt is unsecured.

Business Trends

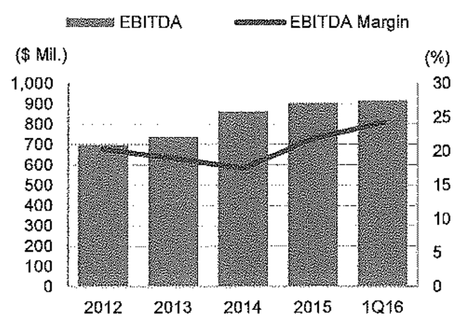
Note: Atmos' fiscal year ends Sept. 30.

Revenue Dynamics



Source: Company data, Fitch.

EBITDA Dynamics



Source: Company data, Fitch.

FitchRatings Corporates

Financial Summary — Atmos Energy Corporation

($ Mil., Sept. 30 Year End, IDR — A–/Rating Outlook Stable)	2012	2013	2014	2015	LTM 12/31/15
Fundamental Ratios					
Operating EBITDAR/(Gross Interest Expense + Rents) (x)	4.2	4.8	5.5	6.2	6.3
FFO Fixed-Charge Coverage (x)	4.4	4.9	5.7	6.4	6.6
Total Adjusted Debt/Operating EBITDAR (x)	3.8	4.0	3.2	3.4	3.7
FFO/Total Adjusted Debt (%)	27.4	25.9	32.0	30.5	28.6
FFO-Adjusted Leverage (x)	3.6	3.9	3.1	3.3	3.5
Common Dividend Payout (%)	58.1	52.7	50.3	50.8	51.3
Internal Cash/Capex (%)	63.3	60.2	74.6	67.4	67.4
Capex/Depreciation (%)	296.8	356.5	328.7	354.5	361.9
Return on Equity (%)	9.2	9.4	9.4	9.9	9.8
Profitability					
Revenues	3,438	3,886	4,941	4,142	3,789
Revenue Growth (%)	(20.9)	13.0	27.1	(16.2)	(23.4)
Net Revenues	1,323	1,412	1,583	1,680	1,700
Operating and Maintenance Expense	(453)	(488)	(506)	(542)	(549)
Operating EBITDA	698	739	865	906	918
Operating EBITDAR	730	771	897	939	951
Depreciation and Amortization Expense	(247)	(237)	(254)	(275)	(278)
Operating EBIT	451	502	611	631	639
Gross Interest Expense	(141)	(130)	(131)	(118)	(118)
Net Income for Common	217	243	290	315	320
Operating Maintenance Expense % of Net Revenues	(34.2)	(34.6)	(32.0)	(32.3)	(32.3)
Operating EBIT % of Net Revenues	34.1	35.6	38.6	37.6	37.6
Cash Flow					
Cash Flow from Operations	587	613	740	837	880
Change in Working Capital	(3)	(24)	(29)	20	38
Funds from Operations	590	637	769	817	842
Dividends	(126)	(128)	(146)	(160)	(164)
Capex	(733)	(845)	(835)	(975)	(1,006)
FCF	(272)	(360)	(241)	(298)	(290)
Net Other Investment Cash Flow	124	81	(3)	13	3
Net Change in Debt	97	286	(166)	249	209
Net Equity Proceeds	(16)	(5)	386	23	34
Capital Structure					
Short-Term Debt	571	368	197	458	763
Total Long-Term Debt	1,956	2,456	2,456	2,455	2,455
Total Debt with Equity Credit	2,527	2,824	2,653	2,913	3,218
Total Adjusted Debt with Equity Credit	2,783	3,080	2,909	3,177	3,474
Total Common Shareholder's Equity	2,359	2,580	3,086	3,195	3,272
Total Capital	4,886	5,404	5,739	6,108	6,490
Total Debt/Total Capital (%)	52	52	46	48	50
Common Equity/Total Capital (%)	48	48	54	52	50

IDR – Issuer Default Rating.
Source: Company data, Fitch.

The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

GUD No. 10580
Atmos Pipeline - Texas
ACSC RFI Set No. 12
Question No. 12-01
Page 1 of 1

REQUEST:

Please refer to the spreadsheet entitled Schedule G_Capital Structure 9-30-16.xlsx and to the tab "Consolidated Balance Detail." Please provide Atmos' monthly long-term debt, short-term debt, and equity balances for 2010 through 2015.

RESPONSE:

The following response was prepared by or under the direct supervision of Barbara W. Myers and Robert B. Hevert, the sponsoring witnesses for this response.

Please see Attachment 1.

ATTACHMENT:

ATTACHMENT 1 - Atmos Pipeline - Texas, ACSC_12-01_Att1 - Apr10-Sep15 LTD, STD, Equity Balances.xlsx, 2 Pages.

Atmos Energy Corporation
Atmos Pipeline - Texas Statement of Intent
Test Year Ending September 30, 2016
Apr10-Sep15 LTD, STD, and Equity Balances

		Long-Term debt (including curr maturities)	Notes Payable	Total Shareholders' Equity
Fiscal 2010	April	2,169,629,944.47	0.06	2,348,752,332.84
	May	2,169,653,480.58	0.06	2,319,880,962.95
	June	2,169,677,016.69	0.06	2,313,730,678.84
	July	2,169,635,076.57	71,999,280.01	2,215,217,184.63
	August	2,169,658,612.68	119,000,000.01	2,182,180,678.02
	September	2,169,682,148.79	126,100,000.01	2,178,347,890.73
Fiscal 2011	October	2,169,705,684.90	184,000,000.01	2,194,318,325.93
	November	2,169,729,221.01	222,000,000.01	2,210,519,203.72
	December	2,159,752,757.12	247,993,436.67	2,274,853,628.27
	January	2,159,710,817.00	256,999,111.12	2,340,555,343.42
	February	2,159,734,353.11	111,000,000.01	2,344,588,854.02
	March	2,159,757,889.22	0.01	2,373,978,719.95
	April	2,159,779,675.33	0.01	2,380,873,149.07
	May	1,809,803,211.44	355,472,694.44	2,349,781,512.32
	June	2,208,540,575.55	-	2,335,824,296.89
	July	2,208,500,463.43	58,000,000.00	2,339,077,331.41
	August	2,208,525,827.54	98,999,572.22	2,295,273,919.23
	September	2,208,551,191.65	206,395,922.27	2,255,421,742.50
Fiscal 2012	October	2,208,576,555.76	277,497,138.86	2,277,354,478.82
	November	2,208,601,919.87	323,994,249.97	2,252,851,929.54
	December	2,206,323,975.98	389,985,444.42	2,267,761,224.37
	January	2,206,283,863.86	344,990,711.12	2,314,124,296.48
	February	2,206,318,353.35	244,996,930.56	2,328,945,546.51
	March	2,206,343,717.24	173,995,744.46	2,360,711,147.64
	April	2,206,369,081.13	159,998,522.23	2,373,914,919.41
	May	2,206,394,445.02	135,995,651.11	2,329,537,937.35
	June	2,206,419,808.91	213,490,562.64	2,354,925,198.02
	July	2,206,379,696.57	289,994,240.01	2,366,764,248.20
	August	1,956,412,143.82	440,895,978.64	2,334,993,257.12
	September	1,956,435,736.88	570,929,287.23	2,359,242,741.27
Fiscal 2013	October	1,956,459,329.94	665,938,625.00	2,369,263,290.67
	November	1,956,482,923.00	719,940,390.55	2,359,529,310.19
	December	1,956,506,516.06	830,890,509.59	2,424,005,107.67
	January	2,455,527,244.00	338,204,816.26	2,494,784,167.40
	February	2,455,553,448.17	292,964,547.23	2,499,179,413.77
	March	2,455,514,177.83	232,997,568.89	2,543,469,132.75
	April	2,455,540,381.94	28,000,000.00	2,550,301,550.29
	May	2,455,566,586.11	109,997,785.55	2,565,856,808.57
	June	2,455,592,790.28	141,997,922.50	2,581,443,813.08
	July	2,455,618,994.45	195,995,477.50	2,605,641,605.94
	August	2,455,645,198.62	252,461,844.96	2,589,624,095.06
	September	2,455,671,402.79	367,983,523.61	2,580,409,324.18

Atmos Energy Corporation
Atmos Pipeline - Texas Statement of Intent
Test Year Ending September 30, 2016
Apr10-Sep15 LTD, STD, and Equity Balances

		Long-Term debt (including curr maturities)	Notes Payable	Total Shareholders' Equity
Fiscal 2014	October	2,455,697,606.96	711,881,958.19	2,589,914,321.96
	November	2,455,723,811.13	626,820,344.03	2,597,645,503.88
	December	2,455,750,015.30	689,795,230.57	2,661,314,056.50
	January	2,455,776,219.47	584,922,359.75	2,698,302,733.95
	February	2,455,802,423.64	94,997,300.03	3,097,294,351.20
	March	2,455,828,627.81	0.01	3,124,760,754.20
	April	2,455,854,831.98	-	3,139,392,521.57
	May	2,455,881,036.15	-	3,101,988,609.95
	June	2,455,907,240.32	-	3,116,684,772.13
	July	2,455,933,444.49	45,000,000.00	3,118,404,415.83
	August	2,455,959,648.66	119,998,472.23	3,070,883,258.42
	September	2,455,985,852.83	196,695,230.69	3,086,231,925.36
Fiscal 2015	October	2,455,074,376.38	261,984,258.07	3,081,163,553.91
	November	2,455,102,899.99	423,924,376.70	3,062,440,613.27
	December	2,455,131,423.60	550,902,916.13	3,063,924,246.58
	January	2,455,159,947.21	466,958,032.79	3,054,362,422.24
	February	2,455,188,470.82	333,978,151.12	3,109,655,513.44
	March	2,455,216,994.43	224,985,819.45	3,139,693,585.34
	April	2,455,245,518.04	122,996,365.00	3,185,985,982.13
	May	2,455,274,041.65	139,996,261.12	3,185,305,501.03
	June	2,455,302,565.26	251,977,147.22	3,238,254,433.83
	July	2,455,331,088.87	305,978,621.16	3,236,730,840.51
	August	2,455,359,612.48	356,895,470.83	3,211,417,593.84
	September	2,455,388,136.09	457,926,706.94	3,194,798,012.86

GUD No. 10580
Atmos Pipeline - Texas
TIEC RFI Set No. 1
Question No. 1-09
Page 1 of 1

REQUEST:

Concerning the direct testimony of APT witness Robert Hevert, please provide the following:

a. Complete copies of all credit rating reports on Atmos Energy Corporation or APT considered in developing his testimony in this proceeding.

b. Please provide complete copies of credit reports on other pipeline companies considered by Mr. Hevert in assessing the investment risk of APT.

c. Please provide complete copies of all reference materials relied on by Mr. Hevert in developing his testimony in this proceeding.

d. In electronic format with all formulas intact, all data and workpapers Mr. Hevert relied on to produce all charts, graphs, figures, and tables in his direct testimony.

RESPONSE:

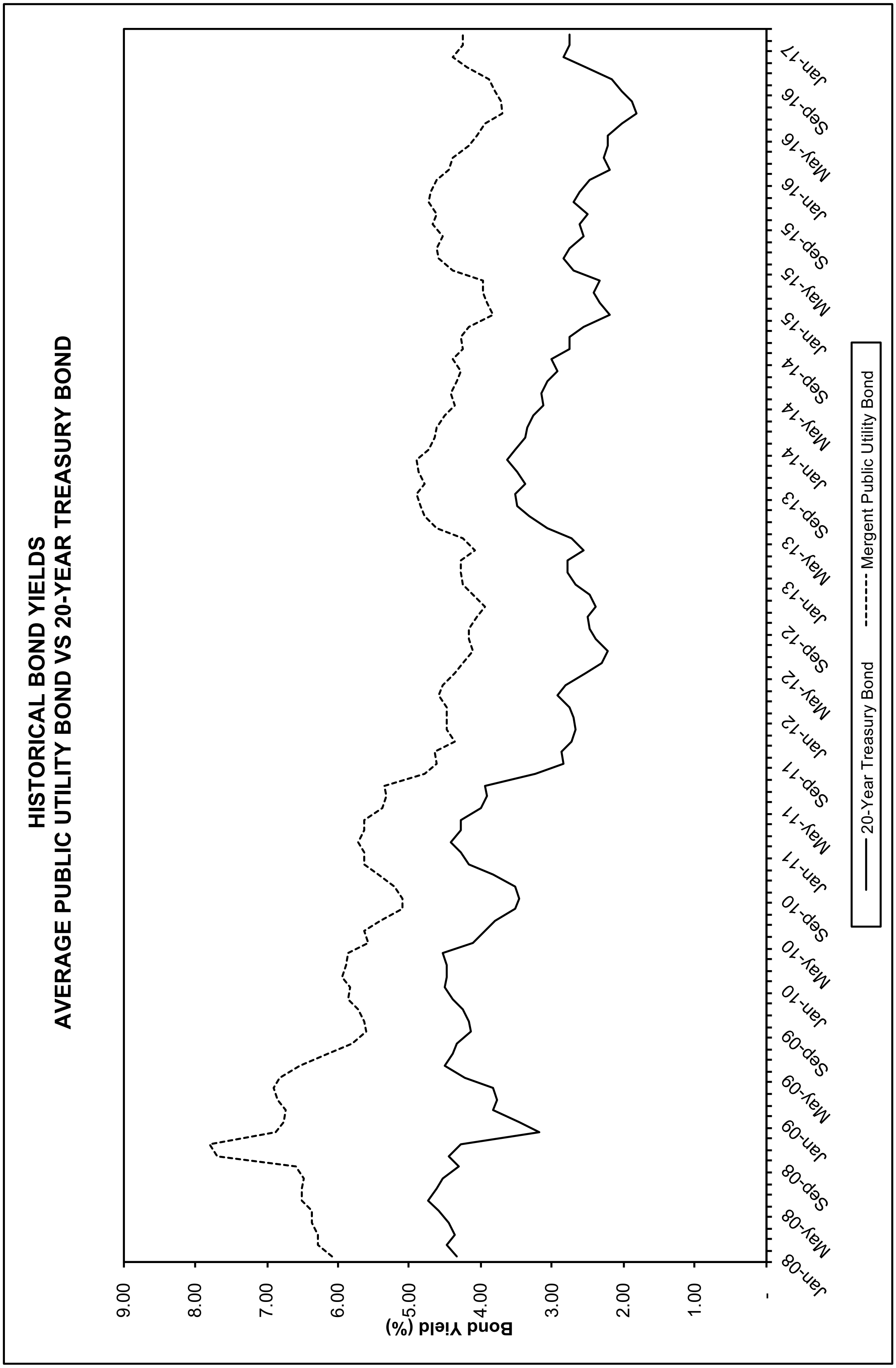
The following response was prepared by or under the direct supervision of Robert B. Hevert, the sponsoring witness for this response.

a) Mr. Hevert did not consider any credit rating reports in developing his testimony in this proceeding.

b) Please see the response to subpart (a).

c) Complete copies of reference material relied on by Mr. Hevert were provided in the Company's response to TIEC RFI No. 1-01.

d) All electronic data and workpapers Mr. Hevert relied on to produce the charts, graphs, figures, and tables in his testimony were provided in the Company's response to TIEC RFI No. 1-01.


HISTORICAL BOND YIELDS
AVERAGE PUBLIC UTILITY BOND VS 20-YEAR TREASURY BOND
Bond Yield (%)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Jan-08
May-08
Sep-08
Jan-09
May-09
Sep-09
Jan-10
May-10
Sep-10
Jan-11
May-11
Sep-11
Jan-12
May-12
Sep-12
Jan-13
May-13
Sep-13
Jan-14
May-14
Sep-14
Jan-15
May-15
Sep-15
Jan-16
May-16
Sep-16
Jan-17
20-Year Treasury Bond
Mergent Public Utility Bond

ATMOS PIPELINE TEXAS
GAS UTILITY PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Feb-17	Jan-17	Dec-16	Nov-16	Oct-16	Sep-16
Atmos Energy	High Price ($)	78.760	76.260	75.250	74.300	74.650	77.720
	Low Price ($)	72.580	72.540	69.570	68.510	68.930	71.610
	Avg. Price ($)	75.670	74.400	72.410	71.405	71.790	74.665
	Dividend ($)	0.450	0.450	0.450	0.450	0.420	0.420
	Mo. Avg. Div.	2.38%	2.42%	2.49%	2.52%	2.34%	2.25%
	6 mos. Avg.	2.40%					
Chesapeake Utilities Corp.	High Price ($)	70.700	67.750	70.000	68.000	64.450	66.460
	Low Price ($)	63.800	63.000	63.450	58.000	57.630	59.120
	Avg. Price ($)	67.250	65.375	66.725	63.000	61.040	62.790
	Dividend ($)	0.305	0.305	0.305	0.305	0.305	0.305
	Mo. Avg. Div.	1.81%	1.87%	1.83%	1.94%	2.00%	1.94%
	6 mos. Avg.	1.90%					
New Jersey Resources	High Price ($)	39.710	37.880	37.300	35.800	34.250	35.590
	Low Price ($)	36.400	33.700	33.550	32.050	30.460	32.270
	Avg. Price ($)	38.055	35.790	35.425	33.925	32.355	33.930
	Dividend ($)	0.255	0.255	0.255	0.255	0.255	0.255
	Mo. Avg. Div.	2.68%	2.85%	2.88%	3.01%	3.15%	3.01%
	6 mos. Avg.	2.93%					
Northwest Natural Gas	High Price ($)	61.700	60.650	61.850	60.200	60.000	63.250
	Low Price ($)	57.350	57.100	55.600	53.500	56.100	57.960
	Avg. Price ($)	59.525	58.875	58.725	56.850	58.050	60.605
	Dividend ($)	0.470	0.470	0.470	0.470	0.470	0.468
	Mo. Avg. Div.	3.16%	3.19%	3.20%	3.31%	3.24%	3.09%
	6 mos. Avg.	3.20%					
South Jersey Industries	High Price ($)	35.450	34.380	34.850	34.080	29.720	31.050
	Low Price ($)	32.450	31.390	32.370	28.040	27.510	28.170
	Avg. Price ($)	33.950	32.885	33.610	31.060	28.615	29.610
	Dividend ($)	0.273	0.273	0.273	0.264	0.264	0.264
	Mo. Avg. Div.	3.22%	3.32%	3.25%	3.40%	3.69%	3.57%
	6 mos. Avg.	3.41%					
Southwest Gas	High Price ($)	86.650	80.760	77.900	76.610	73.230	74.030
	Low Price ($)	78.560	75.630	71.510	69.850	64.260	67.970
	Avg. Price ($)	82.605	78.195	74.705	73.230	68.745	71.000
	Dividend ($)	0.450	0.450	0.450	0.450	0.450	0.450
	Mo. Avg. Div.	2.18%	2.30%	2.41%	2.46%	2.62%	2.54%
	6 mos. Avg.	2.42%					
Spire Inc.	High Price ($)	66.600	66.100	65.200	66.650	63.720	66.520
	Low Price ($)	62.330	63.350	62.450	59.700	59.540	61.960
	Avg. Price ($)	64.465	64.725	63.825	63.175	61.630	64.240
	Dividend ($)	0.525	0.525	0.525	0.490	0.490	0.490
	Mo. Avg. Div.	3.26%	3.24%	3.29%	3.10%	3.18%	3.05%
	6 mos. Avg.	3.19%					

ATMOS PIPELINE TEXAS
GAS UTILITY PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Feb-17	Jan-17	Dec-16	Nov-16	Oct-16	Sep-16
UGI Corp.	High Price ($)	48.580	47.100	46.620	46.660	46.470	48.130
	Low Price ($)	45.440	45.030	43.920	41.790	42.860	44.630
	Avg. Price ($)	47.010	46.065	45.270	44.225	44.665	46.380
	Dividend ($)	0.238	0.238	0.238	0.238	0.238	0.238
	Mo. Avg. Div.	2.03%	2.07%	2.10%	2.15%	2.13%	2.05%
	6 mos. Avg.	2.09%					
Monthly Dividend Yield		2.59%	2.66%	2.68%	2.74%	2.79%	2.69%
6-month Average Dividend Yield		2.69%					

Source: Yahoo! Finance

ATMOS PIPELINE TEXAS
GAS UTILITY PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) First Call/ IBES
Atmos Energy	6.50%	6.00%	5.50%	7.00%	6.90%
Chesapeake Utilities Corp.	5.50%	8.00%	8.00%	6.00%	6.00%
New Jersey Resources	3.50%	2.50%	6.00%	6.00%	6.00%
Northwest Natural Gas	1.50%	6.00%	3.50%	4.30%	4.50%
South Jersey Industries	4.50%	3.00%	1.50%	10.00%	6.00%
Southwest Gas	8.00%	6.50%	6.00%	4.50%	4.00%
Spire Inc.	5.00%	8.00%	4.50%	4.10%	4.04%
UGI Corp.	3.00%	6.50%	8.00%	8.00%	8.00%
Average Growth Rates	4.69%	5.81%	5.38%	6.24%	5.68%
Median Growth Rates	4.75%	6.25%	5.75%	6.00%	6.00%

Sources: Zack's and First Call/Ibes Earnings Reports, retrieved March 17, 2017
Value Line Investment Survey, March 3, 2017

ATMOS PIPELINE TEXAS
GAS UTILITY PROXY GROUP
DCF RETURN ON EQUITY CALCULATION

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of Earnings Growth Rates
Method 1:					
Dividend Yield	2.69%	2.69%	2.69%	2.69%	2.69%
Average Growth Rate	4.69%	5.81%	6.24%	5.68%	5.91%
Expected Div. Yield	2.75%	2.77%	2.77%	2.77%	2.77%
DCF Return on Equity	***7.44%***	***8.58%***	***9.01%***	***8.45%***	***8.68%***
Method 2:					
Dividend Yield	2.69%	2.69%	2.69%	2.69%	2.69%
Median Growth Rate	4.75%	6.25%	6.00%	6.00%	6.08%
Expected Div. Yield	2.75%	2.77%	2.77%	2.77%	2.77%
DCF Return on Equity	***7.50%***	***9.02%***	***8.77%***	***8.77%***	***8.85%***

ATMOS PIPELINE TEXAS
GAS UTILITY PROXY GROUP
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.67%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.51%
4	Risk Premium	
5	(Line 1 minus Line 3)	7.16%
6	Comparison Group Beta	0.75
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.37%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.88%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.67%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.64%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.03%
6	Comparison Group Beta	0.75
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.03%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.66%

ATMOS PIPELINE TEXAS
GAS UTILITY PROXY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
September-16	2.02%
October-16	2.17%
November-16	2.54%
December-16	2.84%
January-17	2.75%
February-17	2.76%
6 month average	2.51%

5 Year Treasury Bond Data

	Avg. Yield
September-16	1.18%
October-16	1.27%
November-16	1.60%
December-16	1.96%
January-17	1.92%
February-17	1.90%
6 month average	1.64%

Source: www.federalreserve.gov, Selected Interest Rates - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.81%
Estimated Market Return	9.85%
Value Line Projected 3-5 Yr. Median Annual Total Return	9.50%
Average of Projected Mkt. Returns	9.67%

Source: Value Line Investment Survey for Windows retreived Feb. 14, 2017

Comparison Group Betas:

Atmos Energy	0.70
Chesapeake Utilities	0.70
New Jersey Resources	0.80
Northwest Natural Gas	0.65
South Jersey Industries	0.80
Southwest Gas	0.75
Spire, Inc.	0.70
UGI Corp.	0.90
Average	0.75

Source: Value Line Investment Survey, March 3, 2017

ATMOS PIPELINE TEXAS
CAPITAL ASSET PRICING MODEL ANALYSIS
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.00%	12.00%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.00%	5.00%	
Historical Market Risk Premium	5.00%	7.00%	6.03%
Gas Distribution Group Beta, Value Line	0.75	0.75	0.75
Beta * Market Premium	3.75%	5.25%	4.52%
Current 20-Year Treasury Bond Yield	2.51%	2.51%	2.51%
CAPM Cost of Equity, Value Line Beta	**6.26%**	**7.76%**	**7.04%**

Source: *2016 SBBI Yearbook, Stocks, Bonds, Bills, and Inflation*,
Duff and Phelps, pp. 2-6, 6-17, 10-30

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF THE ELECTRIC RATES; (2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; (3) APPROVAL OF NEW TARIFFS; (4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	**)**	**CASE NO. 2017-00321**

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

OFFICE OF THE ATTORNEY GENERAL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 29, 2017

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF THE ELECTRIC RATES; (2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; (3) APPROVAL OF NEW TARIFFS; (4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	**CASE NO. 2017-00321**

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit No. ___(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky (“AG”).

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity for the regulated electric operations for Duke Energy of Kentucky, Inc. ("Duke Kentucky", or "Company"). I will also respond to the Direct Testimony of Dr. Roger Morin, witness for Duke Kentucky.

I will also address Duke Kentucky's proposed rider for its proposed Distribution Reliability and Integrity Investment Program ("DCI").

Q. Please summarize your conclusions and recommendations.

A. Based on current financial market conditions, I recommend that the Kentucky Public Service Commission ("KPSC" or "Commission") adopt an 8.80% return on equity for Duke Kentucky in this proceeding. My recommendation is based on the results of a Discounted Cash Flow ("DCF") model analysis. My DCF analysis incorporates my standard approach to estimating the investor required return on equity and includes a proxy group of 19 companies and dividend and earnings growth forecasts from the Value Line Investment Survey, Yahoo! Finance, and Zacks.

I also included two Capital Asset Pricing Model ("CAPM") analyses for additional information. I did not incorporate the results of the CAPM in my recommendation, however the results from the CAPM support my 8.80% ROE recommendation for Duke Kentucky. In fact, my CAPM results are lower than my DCF results.

In Section IV, I respond to the testimony and ROE recommendation of the Company's witness Dr. Morin. I will demonstrate that his recommended ROE of 10.3% overstates the current investor required return for Duke Kentucky. Today's financial environment of low interest rates has been deliberately and methodically supported by Federal Reserve policy actions since 2009. Although the Federal Reserve began to raise short-term interest rates in 2016, both short-term and long-term interest rates remain low. A 10.3% ROE is simply inconsistent with investor required returns for low-risk utilities like Duke Kentucky.

Finally, in Section V of my Direct Testimony I recommend that the Commission reject the Company's proposed DCI. There are several important policy and practical ratemaking reasons as to why the Commission should reject the DCI.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Long-term capital costs as measured by the general level of interest rates in the economy have declined over the last few years. Exhibit No. ___(RAB-2) presents a graphic depiction of the trend in interest rates from January 2008 through November 2017. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of November 2017, the average public utility bond yield was 3.88%, representing a decline of 220 basis points, or 2.20%, from January 2008. Likewise, the 20-year Treasury bond stood at 2.60% in November 2017, a decline of 1.75% (175 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit No. ___(RAB-2) that affected the general level of interest rates?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011.[2]

Beginning in September 2011, the Fed initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist," was designed by the Fed to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities. The Fed began to pare back its purchases of securities in the last few years. On January 29,

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1 (http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm).

2 (http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm)

2014 the Fed stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Fed continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October.[3]

Q. Has the Fed recently indicated any important changes to its monetary policy?

A. Yes. In March 2016, the Fed began to raise its target range for the federal funds rate, increasing it to 1/4% to 1/2% from 0% to 1/4%. The Fed further increased the target range to 1/2% to 3/4% in a press release dated December 14, 2016. On June 14, 2017, the Fed announced a further increase to 1% - 1 ¼%.

On December 13, 2017 the Fed announced yet another increase to the federal funds rate of ¼%. In its announcement, the Fed stated the following:

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. Hurricane-related disruptions and rebuilding have affected economic activity, employment, and inflation in recent months but have not materially altered the outlook for the national economy. Consequently, the Committee continues to expect that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market conditions will remain strong. Inflation on a 12-month basis is expected to remain somewhat below 2 percent in the near term but to stabilize around the Committee's 2 percent objective over the medium term. Near-term risks to the economic outlook appear roughly balanced, but the Committee is monitoring inflation developments closely.
>
> In view of realized and expected labor market conditions and inflation, the Committee decided to raise the target range for the federal funds rate to 1-1/4 to 1-1/2 percent. The stance of monetary policy remains accommodative, thereby supporting strong labor market conditions and a sustained return to 2 percent inflation.
>
> In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation.

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[3] (http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm)

> This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. The Committee will carefully monitor actual and expected inflation developments relative to its symmetric inflation goal. *The Committee expects that economic conditions will evolve in a manner that will warrant gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.* (italics added)[4]

Q. Mr. Baudino, why is it important to understand the Fed's actions since 2008?

A. The Fed's monetary policy actions since 2008 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment. As I will demonstrate later in my testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Are current interest rates indicative of investor expectations regarding the future direction of interest rates?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Morin pointed out in *New Regulatory Finance:*

> "A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information."[5]

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[4] Federal Reserve press release, December 13, 2017 (https://www.federalreserve.gov/newsevents/pressreleases/monetary20171213a.htm).

[5] Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.

Dr. Morin also noted the following:

> There is extensive literature concerning the prediction of interest rates. From this evidence, it appears that the no-change model of interest rates frequently provides the most accurate forecasts of future interest rates while at other times, the experts are more accurate. Naïve extrapolations of current interest rates frequently outperform published forecasts. The literature suggests that on balance, the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change model. The latter model provides similar, and in some cases, superior accuracy than professional forecasts.[6]

Despite recent increases in the general level of interest rates since the second half of 2016, the U.S. economy continues to operate in a low interest rate environment. It is important to realize that investor expectations of higher future interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

Moreover, the current low interest rate environment favors lower risk regulated utilities. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur**.**

Q. How has the increase in interest rates last year affected utility stocks in terms of bond yields and stock prices?

A. Table 1 below tracks movements in the 20-year Treasury bond yield, the Mergent average utility bond yield, and the Dow Jones Utilities Average ("DJUA") from January 2016 through November 2017.

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[6] *Ibid* at 172.

TABLE 1

Bond Yields and DJUA

	20-Year Treasury %	Avg. Utility Bond %	DJUA
2016			
January	2.49	4.62	611.35
February	2.20	4.44	620.70
March	2.28	4.40	668.57
April	2.21	4.16	654.44
May	2.22	4.06	659.44
June	2.02	3.93	716.52
July	1.82	3.70	711.42
August	1.89	3.73	666.87
September	2.02	3.80	668.13
October	2.17	3.90	675.23
November	2.54	4.21	632.67
December	2.84	4.39	645.86
2017			
January	2.75	4.24	668.87
February	2.76	4.25	703.16
March	2.83	4.30	697.28
April	2.67	4.19	704.35
May	2.70	4.19	726.62
June	2.54	4.01	706.91
July	2.65	4.06	726.48
August	2.55	3.92	743.24
September	2.53	3.93	723.60
October	2.65	3.97	753.20
November	2.60	3.88	770.39

Table 1 shows that the 20-year Treasury bond yield was slightly higher in November 2017 than it was in January 2016 before the Fed began raising short-term interest rates. However, the yield on the Mergent average public utility bond was substantially lower in November 2017 (3.88%) than in January 2016 (4.62%). Similarly, the DJUA was substantially higher in November 2017 (770.39) than it was in January 2016 (611.35).

I should also add that the Fed's recent increase in the federal funds rate did not significantly affect current long-term interest rates. On December 19, 2017 Moody's Credit Trends reported that the yield on the average utility bond was 3.90%, not significantly different from the yield from November 2017. Likewise, the Federal Reserve reported that the yield on the 20-Year Treasury bond was 2.66% as of December 19, 2017, about the same as the yield in November 2017.

My conclusion from this data is that even though the Federal Reserve has raised short-term interest rates since March 2016, utility bond yields are lower and the DJUA is higher than they were at the beginning of 2016. Utility stocks and bonds have not been adversely affected by the Fed's raising of the federal funds rate.

Q. How does the investment community regard the electric utility industry as a whole?

A. The Value Line Investment Survey's November 17, 2017 summary report on the Electric Utility (East) Industry noted the following regarding interest rates and utility stocks:

> Most electric utility stocks have performed very well in 2017. Price increases of more than 10% are the rule, not the exception. Despite interest-rate increases from the Federal Reserve (and the expectation of more to come), interest rates are still low, by historical standards, and yields on money-market funds, CDs, and savings accounts remain low enough to be unappealing to some income-oriented investors. Electric utility stocks appeal to these accounts thanks to their above-average dividend yields. Indeed, even at a historically low average yield of 3.3%, this figure is still more than a percentage point above the median of all dividend paying issues under our coverage. Another positive factor for stock prices is takeover speculation. Several deals (mostly involving mid-cap utilities) have occurred in recent years. Most stocks in the Electric Utility Industry are trading within their 2020-2022 Target Price Range, and some are above this range.

This Value Line report also provided an updated discussion of electric utilities' involvement with nuclear plants. Value Line singled out Duke Energy, and noted the following:

> Duke Energy, which has utility-owned plants solely, is in the most stable situation, although the company took a modest charge in the third quarter to write off the costs it incurred for a possible new unit.

Q. In 2017, the Edison Electric Institute ("EEI") published its *2016 Financial Review* of the investor-owned electric utility industry. Please summarize EEI's conclusions with respect to credit ratings for the electric utility industry.

A. EEI's report noted the following with respect to the industry's credit ratings:

> "The industry's average credit rating was BBB+ in 2016, remaining for a third straight year above the BBB average that has held since 2004. Ratings activity, at 67 changes, was in line with the industry's annual average of 70 changes per year since 2008. Upgrades were 73.1% of total actions, the third-highest annual figure for upgrades in our dataset. In fact, the last four years have produced the four highest annual upgrade percentages in our historical data. EEI captures upgrades and downgrades at the subsidiary level; multiple actions within a parent holding company are included in the upgrade/downgrade totals. The industry's average credit rating and outlook are based on the unweighted averages of all Standard & Poor's (S&P) parent company ratings and outlooks.
>
> While the industry's average rating was unchanged at BBB+, the underlying data show a modest strengthening. Six companies received upgrades at the parent level while only two were downgraded. Our universe of U.S. "parent" company electric utilities includes a few that are either a subsidiary of an independent power producer, a subsidiary of a foreign-owned company, or that have been acquired by an investment firm; three of the year's upgrades focused on a relationship with that ultimate parent company. Two other upgrades cited a reduced focus on merchant generation and an improved business risk profile. At January 1, 2017, 74.0% of ratings outlooks were "stable", 18.0% were "negative" or "watch-negative", 6.0% were "positive" or "watch-positive", and 2.0% were "developing".

EEI's analysis shows that the investor-owned electric utility industry had strong, stable, and slightly improving credit metrics in 2016.

Q. What are the current credit ratings and bond ratings for Duke Energy Kentucky?

A. Standard and Poor's ("S&P") current credit rating for Duke Kentucky is A- with a stable outlook. Moody's current long-term issuer rating for the Duke Kentucky is Baa1, again with a stable outlook. These credit ratings are relatively consistent with the recent average utility credit rating of BBB+ as reported by EEI. They also show that Duke Kentucky is a strong, investment grade utility company.

Q. Did Duke Energy, the holding company for Duke Kentucky, provide information to its investors that is relevant to the Commission's evaluation of the allowed rate of return for Duke Kentucky?

A. Yes. Please refer to my Exhibit No. ___(RAB-3), which contains excerpts from Duke Energy's presentation entitled *Fall 2017 Investor Meetings.* I obtained this presentation from Duke Energy's web site.

Page 2 of Exhibit No. ___(RAB-3) shows Duke Energy's presentation of its "attractive risk-adjusted total shareholder return" of 8% - 10%. This total return consists of a dividend yield of 4.0% and a growth rate of 4% - 6%. I note that my recommended ROE for Duke Kentucky of 8.80% falls near the middle of this range. Dr. Morin's recommended 10.3% ROE falls just outside the range.

Page 3 of Exhibit No. ___(RAB-3) presents historical adjusted book ROEs. Duke Energy's presentation shows historical ROEs for the Ohio/Kentucky sector of 10.4% - 11.4%, with an expected ROE of 9% - 9.5%.

Finally, page 4 of Exhibit No. ___(RAB-4) shows that Duke Kentucky recently issued long-term debt at rates in the range of 4.11% - 4.26%. These rates are consistent with recent A/Baa bond yields according to data from the Mergent Bond Record.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for Duke Kentucky.

A. I employed a Discounted Cash Flow ("DCF") analysis using a proxy group of regulated electric utilities. My DCF analysis is my standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, Yahoo! Finance, and Zacks. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I did not rely on the CAPM for my recommended 8.80% ROE for Duke Kentucky, the CAPM provides an alternative approach to estimating the ROE for the Company, albeit a less reliable one.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of an investment. The result of their analyses is a bond and/or credit rating that reflect these risks.

<u>Discounted Cash Flow ("DCF") Model</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 *= the next period dividend*
P_0 *= current stock price*
g *= expected growth rate*
k *= investor-required return*

Under the formula, it is apparent that "k" must reflect the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Duke Kentucky?

A. My first step was to construct a proxy group of companies with a risk profile that is reasonably similar to Duke Kentucky. Since the Company is a subsidiary of Duke Energy, it does not have publicly traded stock. Thus, one cannot estimate a DCF cost of equity on Duke Kentucky directly. It is necessary to use a group of companies that are similarly situated and have reasonably similar risk profiles to the Company.

Q. Please describe your approach for selecting a group of electric companies.

A. For purposes of this case, I relied on the proxy group of companies that Dr. Morin used for his ROE analysis. Dr. Morin discussed his selection criteria on pages 28 through 29 of his Direct Testimony. The main criteria include:

- Companies designated as combination gas and electric utilities by AUS Utility Reports that are also covered by Value Line.
- Elimination of private companies, private partnerships, non-dividend paying companies, and companies that were below investment grade.
- Elimination of companies with less that $1 billion of market capitalization.

Dr. Morin also explained his reasons for eliminating six additional companies on page 29, including companies engaged in recent or ongoing merger activities.

Since the filing of Dr. Morin's testimony, there have been significant events affecting several companies in the proxy group that now warrant their exclusion. First, Avista Corp. announced an agreement for its acquisition by Hydro One, a Canadian company. Thus, Avista should be eliminated from the proxy group. Second, on December 21, 2017 PG&E Corp. announced that it was eliminating its common and preferred stock dividends due to concerns regarding liability connected with California wildfires. PG&E's stock price has plummeted in the last few months as well. Therefore, PG&E Corp. should also be eliminated from the proxy group. Third, SCANA's stock price has fallen significantly over the last few months due to substantial concerns surrounding this company's cancellation of the Summer nuclear power plant. Value Line noted that SCANA's stock price fell 30% since this announced cancellation. Given this substantial change in SCANA's corporate outlook, it should be excluded from the proxy group. Finally, Sempra Energy announced a $9.45 billion acquisition of Oncor in October 2017. This acquisition will significantly affect the stock price and earnings growth for Sempra going forward. Therefore, Sempra should also be excluded from the proxy group.

The resulting proxy group of 19 companies that I used in my analysis is shown in Table 2 below.

TABLE 2

Proxy Group

1	Alliant Energy
2	Ameren Corp.
3	Black Hills
4	CenterPoint Energy
5	Chesapeake Utilities
6	CMS Energy Corp.
7	Consolidated Edison
8	Dominion Energy
9	DTE Energy Co.
10	Duke Energy Corp.
11	Eversource Energy
12	Exelon Corp.
13	Fortis
14	MGE Energy
15	NorthWestern Corp.
16	Pub Sv Enterprise Grp.
17	Vectren Corp.
18	WEC Energy Group
19	Xcel Energy Inc.

Q. What was your first step in determining the DCF return on equity for the comparison group?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to determine the dividend yield. The six-month period I used covered the months from June through November 2017. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the comparison group is 3.11%. These calculations are shown in Exhibit No. ___(RAB-4).

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the electric comparison group?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and Yahoo! Finance. This is the method I typically use for estimating growth for my DCF calculations.

Q. Please briefly describe Value Line, Zacks, and IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site. Like Zacks, Yahoo! Finance also compiles and reports consensus analysts' forecasts of earnings growth.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations. In this respect, I agree with Dr. Morin.

Q. Please explain how you used analysts' dividend and earnings growth forecasts in your constant growth DCF analysis.

Q. Columns (1) through (5) of Exhibit No. ____(RAB-5), page 1, shows the forecasted dividend, earnings, and retention growth rates from Value Line and the earnings growth forecasts from Yahoo! Finance and Zacks. In my analysis, I used four of these growth rates: dividend and earnings growth from Value Line and earnings growth from Zacks and Yahoo! Finance. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows. Value Line is the only source of which I am aware that forecasts dividend growth and my approach gives this forecast equal weight with each of the three earnings growth forecasts.

I note that I used MGE Energy's Yahoo! Finance earnings forecast as a substitute for Zacks, which did not have an available estimate for MGE Energy. I also used Zacks' earnings forecasts as substitutes for the Yahoo! Finance forecasts for Fortis and Xcel Energy, which were not available.

Q. How did you proceed to determine the DCF return of equity for the proxy group?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

Exhibit No. ___(RAB-5), page 2, presents my standard method of calculating dividend yields, growth rates, and return on equity for the comparison group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates to the current group dividend yield of 3.11% to calculate the expected dividend yield for the group of 3.20%. I then added the expected growth rates to the expected dividend yield. In evaluating investor expected growth rates, I use both the average and the median values for the comparison group under consideration.

Q. What are the results of your constant growth DCF model?

A. For Method 1 (average growth rates), the results range from 8.07% to 9.16%, with the average of these results being 8.49%. For Method 2 (median growth rates), the results range from 8.19% to 9.21%, with the average of these results being 8.64%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: *K* = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[7] There is evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results

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7 For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

may also vary widely, which underscores the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for November 30, 2017. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit No. **___**(RAB-6). I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 8.80% to 9.90%. The average of these market returns is 9.35%.

Q. Why did you use median growth rate estimates rather than the average growth rate estimates for the Value Line companies?

A. Using median growth rates is likely a more accurate method of estimating the central tendency of Value Line's large data set compared to the average growth rates. Average earnings and book value growth rates may be unduly influenced by very high or very low 3 - 5-year growth rates that are unsustainable in the long run. For example, Value Line's Statistical Summary shows both the highest and lowest value for earnings and book value growth forecasts. For earnings growth, Value Line showed the highest earnings growth forecast to be 90.5% and the lowest growth rate to be -26.5%. The highest book value growth rate was 96.5% and the lowest was -26%. None of these levels of growth is compatible with long-run growth prospects for the market. The median growth rate is not influenced by such extremes because it represents the middle value of a very wide range of earnings growth rates.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Duff and Phelps compiled a study of historical returns on the stock market in its 2017 SBBI Yearbook. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period is reflective of investor expectations going forward. Exhibit No. ___(RAB-7) presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. Exhibit No. ___(RAB-7) shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2016. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.0% - 7.0%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Duff and Phelps reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[8] Duff and Phelps noted that this growth in the P/E ratio for stocks was subtracted out of the historical risk premium because "it is not believed that P/E will continue to increase in the future." The adjusted historical arithmetic market risk premium is 5.97%, which I have also included in Exhibit No. ___(RAB-7). This risk premium estimate falls near the middle of the market risk premium range.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from June through November 2017. This was the latest month-end available data from the Federal Reserve's Selected Interest Rates (Daily) H.15 web site during the preparation of my Direct Testimony. The 20-year and 30-year Treasury bonds are often used by rate of return analysts as the risk-free rate, but they contain a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both securities as proxies for the risk-free rate of return in my forward-looking CAPM analysis in Exhibit No. ___(RAB-6). This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

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8 *2017 SBBI Yearbook,* Duff and Phelps, pp. 10-28 through 10-30.

A. I obtained the betas for the companies in the proxy group from most recent Value Line reports. The average of the Value Line betas for the proxy group is 0.69.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 7.01% - 7.23%. Using historical risk premiums, the CAPM results are 6.02% - 7.39%.

Conclusions and Recommendations

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 3 below summarizes my return on equity results using the DCF and CAPM for my proxy group of companies.

TABLE 3
SUMMARY OF ROE ESTIMATES

Baudino DCF Methodology:	
Average Growth Rates	
- High	9.16%
- Low	8.07%
- Average	8.49%
Median Growth Rates:	
- High	9.21%
- Low	8.19%
- Average	8.64%
CAPM:	
- 5-Year Treasury Bond	7.01%
- 20-Year Treasury Bond	7.23%
- Historical Returns	6.02% - 7.39%

Q. What is your recommended return on equity for Duke Kentucky?

A. I recommend that the KPSC adopt an 8.80% return on equity for Duke Kentucky. My recommendation is slightly higher than the proxy group DCF results for Methods 1 and 2. In this case, the low end for Method 1 (8.07%) appears to be understated given the range of the other DCF results and, therefore, I have not considered it in my recommendation. The remaining DCF estimates reflect investor expected growth in the range of 5.0% - 6.0% and a DCF range of about 8.20% - 9.20%. My 8.80% is near the midpoint of that range.

Q. Mr. Baudino, are you concerned that your recommended cost of equity is too low?

A. No, not at all. The preponderance of market evidence I examined fully supports my ROE recommendation for the Company in this proceeding. As I described in Section II of my testimony, the U. S. economy is in a low interest rate environment, one that has been supported in a deliberate and considered fashion by Federal Reserve monetary policy. Both my DCF and CAPM ROE estimates show that the investor required ROE for Duke Kentucky, as well as other regulated electric and gas utilities, reflects this low interest rate environment.

IV. RESPONSE TO DUKE ENERGY ROE TESTIMONY

Q. Have you reviewed the Direct Testimony of Dr. Morin?

A. Yes.

Q. Please summarize your conclusions with respect to his testimony and return on equity recommendation.

A. Dr. Morin's recommended 10.3% ROE is overstated, inconsistent with the current low interest rate environment, and not supported by my review of current market evidence.

<u>DCF Model</u>

Q. Briefly summarize Dr. Morin's approach to the DCF model.

A. Dr. Morin's approach was quite similar to mine. He used earnings forecasts from Value Line and Zacks to estimate the investor expected growth component. He also used Value Line's reported dividend yield and multiplied that yield by 1+g to obtain the expected dividend yield in the DCF equation.

Dr. Morin rejected the use of forecasted dividend growth, citing concerns over slower dividend growth over the near term that did not reflect long-run expected earnings growth. Dr. Morin also cited academic studies that supported the use of earnings growth forecasts as superior proxies for investor expected growth.

Dr. Morin also rejected the use of 1 + ½ *g for estimating the expected dividend yield. He also included an adjustment for flotation costs in the DCF model. Dr. Morin's recommended DCF results ranged from 9.03% - 9.44%.

Q. If one excludes flotation costs, how do Dr. Morin's DCF results compare with yours?

A. Our results are quite similar if one excludes flotation costs. Dr. Morin's DCF cost of equity results excluding flotation costs fall in the range of 8.86% - 9.27%. This range is very close to my recommended ROE of 8.80%.

Q. Should flotation costs be included in the cost of equity?

A. No. A flotation cost adjustment attempts to recognize and collect the costs of issuing common stock. Such costs typically include legal, accounting, and printing costs as well as broker fees and discounts. In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. This is not an appropriate assumption regarding investor expectations. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Q. Are Dr. Morin's concerns regarding the use of forecasted dividend growth warranted?

A. No, not at this time. Value Line's forecasted dividend growth rates for the companies in the proxy group are not at all out of line with the earnings growth forecasts from Value Line, Zacks, and Yahoo! Finance. In addition, dividends are the cash flows investors receive from their investments in utility stocks and if credible dividend growth forecasts are available, such as those from Value Line, then they certainly should be included in the DCF model. I agree with Dr. Morin's position with respect to the importance of earnings growth forecasts and their influence on investor expectations. That is why I gave 75% weight to earnings growth forecasts in my formulation of the DCF model.

Q. You used 1 + .5*g to calculate the expected dividend yield in the DCF equation. Does this approach understate the expected dividend yield compared to the 1 + g approach?

A. No, and in fact the two approaches do not yield significantly different results, although the 1+g approach results in a slightly higher expected dividend yield. Using 1+.5*g assumes that the growth in dividends received by an investor occurs mid-year, rather than throughout the entire year. The 1+g approach assumes that the investor receives the full amount of growth throughout the next year. Given the timing of dividend increases and the level of the current dividend, the investor may or may not actually receive four quarters of growth in the dividend payment during the next year. Thus, applying one-half of the expected growth rate to the current quarterly dividend recognizes that the investor may not actually receive a full year of increased dividend payments from the time the DCF calculation was made.

<u>CAPM and ECAPM</u>

Q. On page 32 of his Direct Testimony, Dr. Morin recommended using a forecasted interest rate of 4.4% for the risk free rate of return. Is it appropriate to use forecasted interest rates for purposes of estimating the current ROE for Duke Kentucky?

A. No, definitely not. Current interest rates and bond yields embody all the relevant market data and expectations of investors, including expectations of changing future interest rates. Current interest rates present tangible market evidence of investor return requirements today, and these are the interest rates and bond yields that should be used in the CAPM, ECAPM, and in the bond yield plus risk premium analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

Q. Please explain in more detail why the Commission should reject the forecasted Treasury yield recommended by Dr. Morin.

A. As I stated in Section II my Direct Testimony, current interest rates embody investor expectations based on their assessments of all available market information. This includes the interest rate forecasts cited by Dr. Morin as well as statements and actions from the Federal Reserve. The KPSC should not invest in the interest rate forecasts cited by Dr. Morin in determining a fair rate of return for Duke Kentucky in this proceeding.

There is evidence that economists have systematically overestimated interest rates in recent years. Jared Bernstein wrote the following in a recent article in the New York Times[9]:

> In the early 1980s, forecasters did a good job of predicting the path of bond rates, though their job was a bit easier than usual because rates were so highly elevated that it was a pretty sure bet they'd be headed back down. ("Regression to the mean," for all you statistics fans.)
>
> But since the mid-1990s, government forecasters have consistently overestimated this critical variable.
>
> This "consistently" point is essential. Most economic forecasts are off one way or the other — too high or too low, but they tend to be pretty much balanced in either direction. But on the 10-year bond rate, the errors are systemic.

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[9] "We Keep Flunking Forecasts on Interest Rates, Distorting the Budget Outlook", Jared Bernstein, *New York Times*, Feb. 23, 2015.

Forecasters are regularly overestimating and thus regularly overstating, all else being equal, future interest payments on the debt.

Another article by Akin Oyedele entitled "Interest Rate Forecasters Are Shockingly Wrong Almost All Of The Time"[10] showed that from June 2010 through June 2015 interest rate forecasts were wrong most of the time. Mr. Oyedele noted that 2014 "was particularly bad, when strategists became too optimistic that the Federal Reserve would hike rates."

Q. Is there support for the position that today's currently low interest rates are part of a long-term trend?

A. Yes. In a weekly blog at the Brookings Institution, former Federal Reserve Chairman Ben Bernanke wrote the following:[11]

> Interest rates around the world, both short-term and long-term, are exceptionally low these days. The U.S. government can borrow for ten years at a rate of about 1.9 percent, and for thirty years at about 2.5 percent. Rates in other industrial countries are even lower: For example, the yield on ten-year government bonds is now around 0.2 percent in Germany, 0.3 percent in Japan, and 1.6 percent in the United Kingdom. In Switzerland, the ten-year yield is currently slightly negative, meaning that lenders must pay the Swiss government to hold their money! The interest rates paid by businesses and households are relatively higher, primarily because of credit risk, but are still very low on an historical basis.
>
> Low interest rates are not a short-term aberration, but part of a long-term trend. As the figure below shows, ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak above 15 percent in 1981, and have been declining ever since. That pattern is partly explained by the rise and fall of inflation, also shown in the figure. All else equal, investors demand higher yields when inflation is high to compensate them for the declining purchasing power of the dollars with which they expect to be repaid. But yields on inflation-protected bonds are also very low today; the real or inflation-adjusted return on lending to the U.S. government for five years is currently about *minus* 0.1 percent.
>
> Why are interest rates so low? Will they remain low? What are the implications for

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[10] Akin Oyedele, "Interest Rate Forecasters Are Shockingly Wrong Almost All of the Time", *Business Insider*, July 18, 2015.

[11] Ben S. Bernanke, "Why Are Interest Rates So Low", Weekly Blog, Brookings, March 30, 2015. https://www.brookings.edu/blog/ben-bernanke/2015/03/30/why-are-interest-rates-so-low/

the economy of low interest rates?

If you asked the person in the street, "Why are interest rates so low?", he or she would likely answer that the Fed is keeping them low. That's true only in a very narrow sense. The Fed does, of course, set the benchmark nominal short-term interest rate. The Fed's policies are also the primary determinant of inflation and inflation expectations over the longer term, and inflation trends affect interest rates, as the figure above shows. But what matters most for the economy is the real, or inflation-adjusted, interest rate (the market, or nominal, interest rate minus the inflation rate). The real interest rate is most relevant for capital investment decisions, for example. The Fed's ability to affect real rates of return, especially longer-term real rates, is transitory and limited. Except in the short run, real interest rates are determined by a wide range of economic factors, including prospects for economic growth—not by the Fed.

Q. What does a 4.4% forecasted interest rate suggest with regards to investors holding 30-year Treasury bonds currently?

A. It suggests that investors today are expecting to incur huge losses in the value of their investments in long-term Treasury bonds, which makes no economic sense whatsoever.

The price of a bond moves in the opposite direction of its yield. In other words, given a certain current bond coupon and price, if the required yield on that bond increases then the price of the bond goes down. Alternatively, if the required yield declines, then the price of the bond increases. This relationship can be illustrated with the following simplified example. Assume a current 30-year Treasury bond has a coupon of $2.75 and a price of $100, resulting in a current yield of 2.75%. This is the approximate current yield for 30-year Treasury bonds in the market at the time I prepared this testimony. If interest rates were to rise in the economy such that the required yield on the 30-year Treasury increased to 4.4%, then the price of our existing 30-year Treasury bond would fall to $62.50 from $100, given the coupon of $2.75. This represents a loss to our current bond investor of 37.5%.

The point here is that if investors were certain that there would soon be a substantial increase in interest rates, the rational response would be to immediately discount what they were willing to pay currently for the 30-year Treasury bond rather than pay $100 and suffer certain significant losses to the value of their bonds. The fact that the 30-Year Treasury bond is currently yielding about 2.75% suggests that investors do not expect Treasury Bonds yields to drastically increase and, as a result, cause dramatic losses in their investments.

Q. How does Dr. Morin's forecasted Treasury yield of 4.4% compare with the recent bond yields on debt issued by Duke Kentucky?

A. I cited yields of 4.1% - 4.26% on long-term debt recently issued by Duke Kentucky in Section II of my Direct Testimony. Dr. Morin's forecasted yield on the 30-year Treasury bond of 4.4% is even higher than the current debt yield for Duke Kentucky, debt that is much riskier than the long-term Treasury bond backed by the full faith and credit of the U.S. government.

Clearly, Dr. Morin's recommended 4.4% forecasted interest rate fails to properly reflect investor expectations in today's market. It results in inflated results for his CAPM, ECAPM, and historical risk premium studies.

Q. Please compare and comment upon Dr. Morin's CAPM recommendation of 9.3% and your CAPM results based on historical risk premiums.

A. If we compare our results using the arithmetic historical risk premium of 7.0%, our results range from 7.41% - 9.3%. The major factor driving the difference here is Dr. Morin's use of the 4.4% forecasted Treasury yield versus my use of a current 20-year

Treasury bond yield. I strongly recommend against the Commission using a forecasted Treasury yield in this case. However, if the Commission wishes to consider forecasted bond yields, then I recommend it consider the range of results using both current and forecasted Treasury bond yields. The midpoint of this range is 8.4%.

Q. Beginning on page 44 of his Direct Testimony, Dr. Morin described the Empirical CAPM ("ECAPM") analysis. Is this a reasonable method to use to estimate the investor required ROE for Duke Kentucky?

A. No. The ECAPM is supposed to account for the possibility that the CAPM understates the return on equity for companies with betas less than 1.0. The use of an adjustment factor to "correct" the CAPM results for companies with betas less than 1.0 suggests that published betas by such sources as Value Line are incorrect and that investors should not rely on them in formulating the CAPM. Further, Dr. Morin did not present evidence that investors use the adjustment figure he calculated (alpha) in his ECAPM.

Dr. Morin's ECAPM also suffers from the defect of using his recommended forecasted long-term Treasury yield. If one inserts the December 14, 2017 30-year Treasury yield into his ECAPM equation, the result is as follows:

2.75% + .25(7.0%) + .75*.70 * (7.0%) = 8.18% ECAPM ROE

__**Historical Risk Premium Estimates**__

Q. Please summarize Dr. Morin's historical risk premium approach.

A. Dr. Morin presented his historical risk premium approach beginning on page 48 of his Direct Testimony. Dr. Morin calculated an historical risk premium using the actual realized return on equity for the S&P Utility Index and then subtracting the long-term

Treasury bond return for each year over the period 1930 – 2015. This historical risk premium was 6.1%. When added to Dr. Morin's recommended forecasted Treasury bond yield of 4.4%, his recommended cost of equity was 10.5% without flotation costs.

Q. Please respond to the Company witnesses' risk premium analysis.

A. Generally, the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time and with varying risk perceptions of investors. As such, this approach is a "blunt instrument", if you will, for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on an historical risk premium analysis over a certain historical period.

Q. Does Dr. Morin's historical risk premium analysis suffer from the use of a forecasted Treasury bond yield?

A. Yes, most definitely. If the Commission wishes to consider Dr. Morin's historical risk premium analysis, then the current yield on the 30-year Treasury bond should also be used. Using this current yield and the historical risk premium calculated by Dr. Morin, the resulting ROE estimate would be:

2.75% + 6.1% = 8.85% ROE

The resulting ROE in this case is nearly the same as my recommended ROE of 8.8%. This result shows the magnitude of the overstatement in Dr. Morin's ROE calculations when current, not forecasted, interest rates are used.

Allowed Risk Premium Estimates

Q. Please summarize Dr. Morin's allowed risk premium ROE analysis.

A. Dr. Morin developed an historical risk premium using Commission-allowed returns for regulated utility companies from 1986 through 2016. He also used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. On page 53 of his Direct Testimony, Dr. Morin calculated the risk premium ROE to be 10.5%.

Once again, Dr. Morin's 10.5% risk premium ROE was inflated by using a forecasted Treasury bond yield of 4.4%. If one uses the approximate current yield on the 30-year Treasury, the resulting ROE is as follows:

8.19 – (0.4705 * 2.75%) + 2.75% = 9.65% ROE

I strongly recommend that the Commission reject this unreasonable forecasted Treasury bond yield used by Dr. Morin.

Dr. Morin's ROE Conclusions

Q. On page 63 of his Direct Testimony, Dr. Morin used the upper half of his ROE range to support his recommended ROE for Duke Kentucky. Should the Commission consider only the upper half of an ROE range of results in determining the ROE for Duke Kentucky in this case?

A. No. My review of Duke Kentucky's current credit ratings suggests that Duke Kentucky does not merit any additional increment to its ROE for alleged additional risk. As I stated in Section II, Duke Kentucky's current credit ratings are A- from Standard and Poor's and Baa1 from Moody's. These current ratings are consistent with current industry credit ratings and demonstrate that Duke Kentucky is a strong, investment grade utility company. Nothing in these credit ratings support adding an additional increment to Duke Kentucky's ROE compared to the proxy group used by Dr. Morin and myself.

Q. Should the Commission give Duke Kentucky a higher authorized ROE because of its ongoing construction program?

A. Definitely not. The Commission already provides Duke Kentucky the opportunity to file its rate case using a future test period, which in this case includes the 12-month period ending March 31, 2019. Duke Kentucky can include forecasted capitalization up to that date, which assists the Company in mitigating regulatory lag. It would not be fair to ratepayers to inflate the ROE to cover Duke Kentucky's future investments that have not been reviewed by the Commission for prudence and for being used and useful. If Duke Kentucky's ongoing construction program causes the Company's ROE to decline in the future, it can always file a rate case with the Commission to address the situation.

Q. Should the Commission allow a higher ROE to Duke Kentucky due to its small size?

A. No. Dr. Morin provided no evidence to suggest that a size premium applies to smaller regulated utility companies, which on average are quite different from the groups of companies included in the Duff and Phelps' research on size premiums. I reviewed the discussion of size premiums from Chapter 7 of the *2017 SBBI Yearbook*, the source I used for my historical CAPM analyses. The data from Duff and Phelps shows the following betas for groups of smaller capitalization stocks[12]:

Mid-level capitalization	1.12
Low capitalization	1.22
Micro-capitalization	1.35

The groups of smaller capitalization stocks have much higher betas than regulated utility companies. The average beta for my proxy group is 0.69, which is far below even the mid-level capitalization groups of stocks studies by Duff and Phelps. The low and micro capitalization stocks have even higher betas. This shows that the many unregulated stocks included in the Duff and Phelps study are far more risky than regulated utilities like Duke Kentucky. I recommend that the Commission reject Dr. Morin's argument regarding Duke Kentucky's small size as a basis for increasing the ROE.

Q. Is asset concentration for Duke Kentucky a sufficient basis for a higher than average ROE?

A. No. Once again, any additional risk from Duke Kentucky's generation mix would have been factored into the Company's current credit ratings, which are A-/Baa1 as I noted earlier.

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[12] *2017 SBBI Yearbook*, Duff and Phelps, pg. 7-16.

V. DUKE KENTUCKY'S PROPOSED DCI

Q. Did you review the Company's proposed Distribution Capital Investment ("DCI") rider?

A. Yes. Duke Kentucky witnesses Anthony J. Platz and William Wathen provided detailed descriptions of the Company's proposed DCI and support as to why the Commission should approve it. Duke witness Lawler presented a template for rider DCI in her Direct Testimony.

Q. What is your recommendation regarding the proposed DCI?

A. The Commission should reject Duke Kentucky's proposed DCI. There are several important policy and practical reasons why the DCI should not be approved. I will present these reasons later in my testimony after I provide a summary of the proposed DCI.

Q. Please provide an overview of Duke Kentucky's proposed DCI.

A. According to Mr. Wathen, the purpose of the DCI "is to provide a mechanism for the Company to accelerate deployment of programs to improve its electric delivery system integrity or reliability as well as a means for the Company to more timely recover its capital invested for these project, thereby reducing regulatory lag that would otherwise occur through pure base rate recovery of these types of program costs and that must compete with other projects funded through the Company's base rates."[13] If the DCI is approved, Duke would make annual filings to establish new DCI rates based on

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[13] Wathen Direct at 26, lines 8 through 14.

incremental investment in eligible plant as determined by the Commission. Initially, Mr. Platz testified that the Company will include costs associated with its Targeted Underground Program ("TUG"). However, Mr. Wathen also explained that the Company may propose new programs for inclusion in the rider. The rate of return would be set at the overall pre-tax rate of return approved by the Commission in this case. The revenue requirement for the rider would be rolled into base rates in a future rate proceeding. Duke commits that if the Company has not had another electric base rate case filing within three years after the implementation of rider DCI, then it will submit testimony supporting the continuation of the approved rate of return or propose a new rate of return for the Commission to consider for the rider.

Mr. Platz provided details regarding the Company's proposed TUG beginning on page 25 of his Direct Testimony. Mr. Platz explained that this program will "identify specific areas of its distribution system that experience higher than acceptable frequency of outages and replace overhead wires with underground cables in an effort to harden the system, thereby increasing overall reliability."[14] Mr. Platz provided estimated expenditures for this program on Tables 3 and 4 of his Direct Testimony.

Mr. Platz also testified that although "*Duke Energy Kentucky cannot guarantee that system reliability or customer satisfaction scores will improve due to a particular program or initiative, or that a particular level of system performance will result from*

[14] Platz Direct Testimony at 25, lines 13 through 15.

implementing its infrastructure improvement plans, doing nothing is sure to erode current levels."[15] (italics added)

Q. In general terms, please explain why the Company's proposed DCI should be rejected.

A. As a general matter, automatic capital and/or investment adjustment clauses such as the DCI are poor policy. This sort of automatic adjustment clause that allows the pass-through of capital costs simply does not allow the requisite amount of regulatory scrutiny that a full base rate proceeding provides. In a base rate case, the Commission, its Staff, and other parties have time to conduct a detailed examination and review all the elements of a utility's revenue requirement to ensure that the costs ratepayers are required to pay are prudently incurred. Duke Kentucky's proposed DCI would enable the Company to pass though significant new costs without this type of regulatory scrutiny. Although the utility and its shareholders would certainly benefit from increased cash flows from the DCI, ratepayers are far less assured that costs subject to this treatment are prudently incurred. Thus, the DCI effectively shifts the risk of investment from the utility and its management and shareholders to ratepayers.

Q. Does the Company's proposed DCI provide for a reasonable review process to ensure that eligible costs are prudently incurred?

A. No. Duke Kentucky's proposed DCI lacks any mechanism for Commission review to

[15] Platz Direct Testimony at 32-33, lines 22 through 23 and 1 through 2.

determine if costs passed through the DCI have been prudently incurred. Mr. Platz testified that rider DCI would be trued-up for actual costs and audited by the Commission to ensure that the Company is not over- or under-earning.[16] However proposed rider DCI fails to include a prudence review process. Simple auditing and revenue reconciliation cannot assure customers that the costs for which they are being charged through the DCI are reasonable and prudent. Further, this simple reconciliation process does not provide for any input from intervenors.

Q. Did Duke Kentucky quantify any customer benefits from the proposed DCI or from its proposed TUG?

A. No. In fact, the earlier quote from Mr. Platz's testimony suggests that the Company cannot guarantee there will be any reliability or other benefits to customers from its TUG.

Q. How should Duke Kentucky quantify the system benefits to customers from distribution system reliability programs like the Targeted Underground Program?

A. Two of the most common measures of distribution system reliability are the System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI"). In simple terms, SAIDI measures the average outage duration for each customer. SAIFI measures how frequently a customer is interrupted during a period of time, usually a year. Neither Mr. Platz nor Mr. Wathen, or any

[16] Platz Direct Testimony at page 36, lines 7 through 9.

other Duke witness provided any analyses of whether SAIDI and SAIFI indices would improve from the Targeted Underground Program in direct testimony.

Q. Did Duke Kentucky provide SAIFI and SAIDI measures in response to discovery from the AG?

A. Yes. Duke Kentucky provided forecasted SAIFI and SAIDI measures in response to AG-DR-1-89. Please refer to Exhibit No. ____(RAB-8), which includes Duke Kentucky's forecasted SAIFI and SAIDI ratios from 2017 through 2028 as provided in an attachment to the response. This attachment provides forecasted values with and without the undergrounding program that Duke Kentucky is requesting be included in the DCI. The frequency of system outages as measured by SAIFI is basically unchanged if the undergrounding program in undertaken. This means that there is no significant system-wide impact from undergrounding on the frequency of outages on Duke Kentucky's distribution system.

Duke Kentucky also forecasted slight improvements in SAIDI, which measures the duration of an outage, or the amount of time that a customer's service would be interrupted during an outage. By 2028, the Company forecasted that system-wide SAIDI would improve by 6 minutes with the inclusion of the TUG, from 66 to 60 minutes.

Duke Kentucky also forecasted the impact of the program in terms of analyses of what it termed "major event days" ("MED") of outages on its system. The Company stated that it expected a 15% - 20% reduction in MED outage events and a 15% - 20% reduction in MED outage duration.

Q. Is the Targeted Underground Program something that Duke Kentucky should be doing as part of its normal budgeting and system operations?

A Yes, this appears to be the case. On page 25, lines 13 through 14, Mr. Platz noted that this program identifies areas of the Company's distribution system "that experience higher than acceptable frequency of outages." Indeed, if the areas identified by the Company are experiencing outage rates that are unacceptable, then those areas should be considered high priority for Duke Kentucky and should be fully addressed by the Company whether or not it has a DCI in place. Duke Kentucky customers are entitled to expect reliable service at just and reasonable rates and it is the Company's responsibility to ensure those outcomes for its customers.

Q. Has Duke Kentucky shown a financial need for its proposed DCI?

A. No. Duke Kentucky did not present any financial analyses and/or projections showing that it needed the proposed DCI to support ongoing financing of its Targeted Underground Program or other programs that the Company may include in future DCI filings.

Q. Has Duke Kentucky been able to make continuing investments in its distribution system without the need of its proposed DCI?

A, Yes. According to the Direct Testimony of Mr. James Henning, "Duke Energy Kentucky has regularly made prudent investments in it distribution system, as needed for its continued safe, reliable, and efficient operation." Duke Ketucky has been able to make these investments despite not having filed a rate case in over eleven years according to Mr. Wathen.[17] Quite frankly, Duke Kentucky failed to make the case that it needs a DCI to continue to make these distribution system investments for its customers.

Q. Is there a choice for the Commission between the DCI and "doing nothing?"

A. No. The DCI and rider have been proposed by the Company as a means to "accelerate deployment of programs to improve its electric delivery system integrity or reliability as well as a means for the Company to more timely recover its capital invested for these project."[18] As a prudently operated regulated utility, the Company presently and continually works to "identify specific areas of its distribution system that experience higher than acceptable frequency of outages" to improve service reliability.[19] It then utilizes the budgeting process to prioritize and select the specific projects that it will undertake.

The DCI will not change the essential process already in place. However, the DCI will "accelerate" the Company's spend rate and will increase rates more quickly than if the DCI is rejected, both of which are acknowledged by Mr. Wathen and Mr. Platz.

Q. Is there a behavioral aspect that will change if the DCI and rider are adopted?

A. Yes. Presently, the Company is constrained and must prioritize its capital spending

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[17] Wathen Direct Testimony at 26, lines 20 through 21.

[18] Wathen Direct at 26.

[19] Platz Direct at 25.

between rate cases in order to maintain its earned return. This occurs as a natural result of regulatory lag and works to the benefit of Duke Kentucky's customers. As a general matter, the base ratemaking structure requires the Company to focus on specific reliability projects with higher priority or value and minimizes growth in costs that must be recovered from customers.

In contrast, if the DCI and rider are adopted, these incentives are largely removed through the elimination of regulatory lag. The DCI and rider will provide the Company incentives to expand the universe of reliability projects to include those with lower priority or value. The greater the spend rate, the greater the Company's top line revenues and bottom line earnings, but at the expense of more rapid increases in customer rates. This will provide the Company a strong incentive to expand the projects and/or types of costs that can be included in the DCI and rider well beyond the initial TUG.

Q. The proposed DCI would allow the Company to include additional programs in the future. Does this aspect of the DCI pose additional concerns?

A. Yes, it certainly does. It appears that the TUG would only be the first program included in the proposed DCI. Duke would be free to request that future programs be included in the DCI, subject to Commission approval. Costs would certainly increase over time as the Company included more of these distribution programs, which would not be subject to the same prudence and cost scrutiny that would be available in a base rate proceeding.

Q. On page 26, lines 14 through 15 of his Direct Testimony Mr. Wathen testified that minimizing regulatory lag "also allows the Company and all stakeholders to avoid the expense of multiple rate cases." Do you agree with this statement?

A. No. First, given the fact that it has been over 11 years since the Company filed its last base rate case and that the Company made ongoing "prudent investments" in its distribution system over that time, it is by no means clear how much expense ratepayers would save from the alleged future multiple rate cases mentioned by Mr. Wathen. Second, base rate cases afford ratepayers added insurance that the costs of Duke's distribution system investments are prudently incurred. The Company's proposed DCI does not offer the same assurance. Further, the Company is afforded recovery for reasonably incurred rate case expenses when it does file for a rate increase.

Q. Has the Commission previously approved a DCI-type mechanism for a jurisdictional electric utility?

A. According to the Company's response to Staff-DR-02-055, Duke Kentucky was not aware of any similar ratemaking mechanisms approved by the Commission for jurisdictional electric utilities.

Q. If the Commission were to consider adoption of a mechanism similar to the proposed DCI, what elements should be included in such a proposal?

A. There are several key elements that the Commission should consider in adopting any automatic capital adjustment program such as the DCI.

First, I recommend that the Commission place a yearly cap on rate increases associated with such a rate mechanism. In order to limit the effect on customers from a newly approved DCI-type mechanism, a 2.5% yearly increase over current authorized tariff rates is reasonable.

Second, I recommend that the Commission place a cumulative cap on rate increases from the rate mechanism between base rate cases. I recommend a reasonable total rate increase cap of 5% to protect customers from the kind of open ended rate increases that would result from Duke Kentucky's proposed DCI.

Third, the Commission should include offsets that reflect the build-up of accumulated depreciation and accumulated deferred income taxes ("ADIT") associated with investments included in a DCI-type of mechanism during the period that the mechanism is in effect. This treatment reflects the way these investments would be treated in rate base during a base rate proceeding. In addition, the Commission should include an incremental offset for the increase in accumulated depreciation and ADIT on total distribution plant. This reflects the fact that total distribution plant will continue to depreciate between rate cases. If the Commission allows Duke Kentucky to flow through costs of new plant with a DCI-type mechanism, it should also recognize the reduction in distribution plant rate base between rate cases, which would serve to lower rates for customers. Finally, Duke Kentucky should be required to reflect the retirement of overhead distribution plant that will be replaced by new underground facilities, along with the reduction in associated depreciation expense.

Fourth, the Company should only be allowed to include actual investment costs after the year they are closed to plant in service. The Company should not be allowed to include any projected costs in the DCI.

Fifth, I recommend that a DCI-like mechanism be limited to a three-year pilot program. Duke Kentucky's current DCI proposal has no specified endpoint, except that the costs collected through the DCI would be rolled into base rates in the Company's next base rate proceeding. I recommend that this program end after three years and that the Company be required to file a full base rate case at that time. At some point, the Commission should assess the workability and reasonableness of the DCI-type mechanism within a full base rate case proceeding. This ensures that the Commission, its Staff, and other parties can review the reasonableness of cost recovery from ratepayers.

Q. Does this complete your Direct Testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF THE ELECTRIC RATES; (2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; (3) APPROVAL OF NEW TARIFFS; (4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	**)**	**CASE NO. 2017-00321**

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

OFFICE OF THE ATTORNEY GENERAL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 29, 2017

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Richard A. Baudino

Sworn to and subscribed before me on this
28th day of December 2017.

Notary Public

RANDY A. FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2020
COBB COUNTY, GEORGIA

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Director of Consulting, Consultant** - Responsible for consulting assignments in revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
Atmos Cities Steering Committee
Canadian Federation of Independent Businesses
CF&I Steel, L.P.
Cities of Midland, McAllen, and Colorado City
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service

Expert Testimony Appearances
of
Richard A. Baudino
As of December 2017

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

**Expert Testimony Appearances
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As of December 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

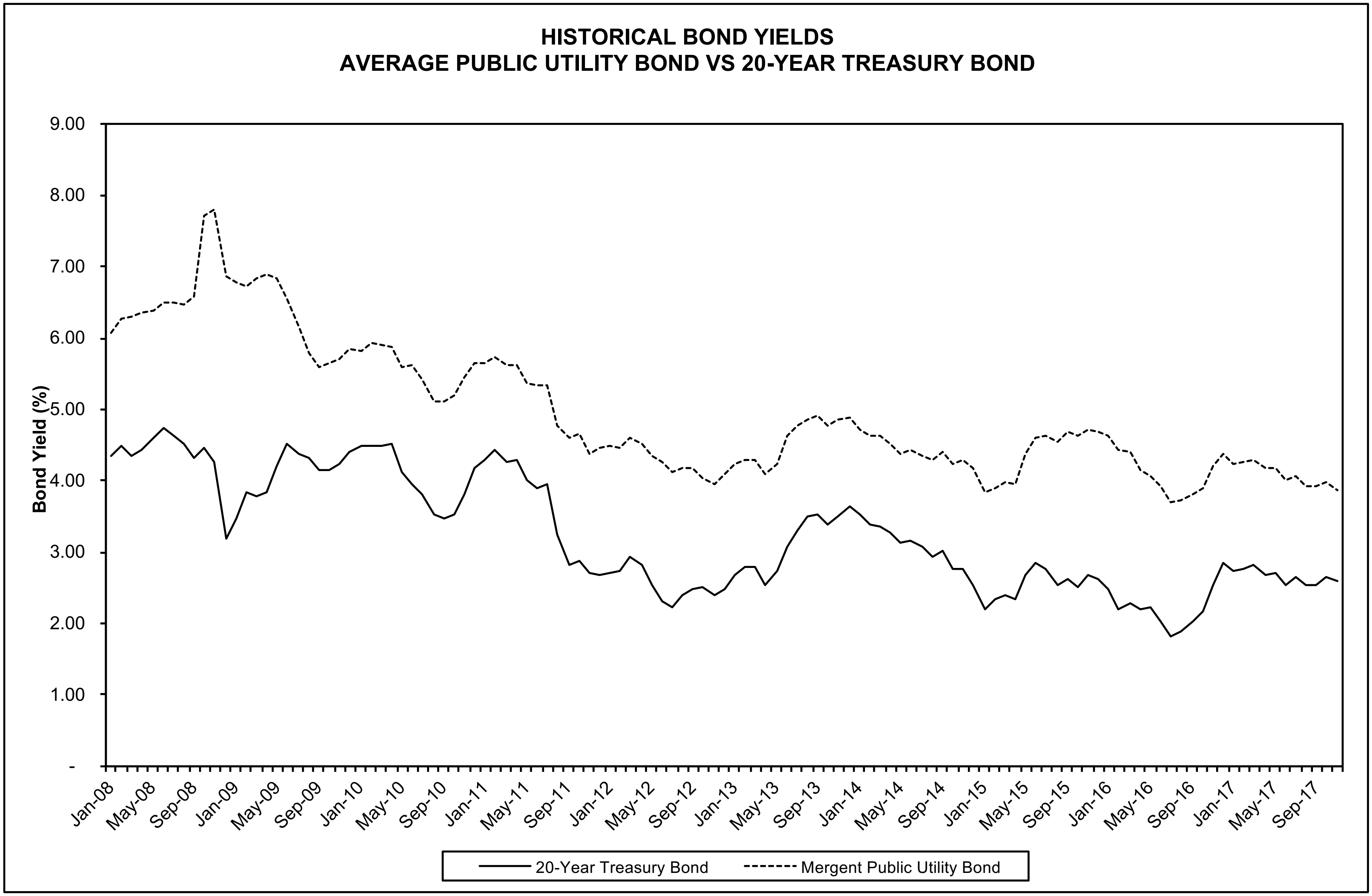
Expert Testimony Appearances
of
Richard A. Baudino
As of December 2017

Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
08/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
08/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation
09/16	2016-00162	KY	Kentucky Office of the Attorney General	Columbia Gas of Ky.	Return on equity, cost of short-term debt
09/16	16-0550-W-P	WV	West Va. Energy Users Gp.	West Va. American Water Co.	Infrastructure Replacement Program Surcharge
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring fencing and other conditions for acquisition, service quality and reliability
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP and Sharyland Dist. and Transmission Services, LLC	Return on equity
02/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
03/17	10580	TX	Atmos Cities Steering Committee	Atmos Pipeline Texas	Return on equity, capital structure, weighted cost of capital
03/17	R-3867-2013	Quebec, Canada	Canadian Federation of Independent Businesses	Gaz Metro	Marginal Cost of Service Study

Expert Testimony Appearances
of
Richard A. Baudino
As of December 2017

Date	Case	Jurisdict.	Party	Utility	Subject
05/17	R-2017-2586783	PA	Philadelphia Industrial and Commercial Gas Users Gp.	Philadelphia Gas Works	Cost and revenue allocation, rate design, Interruptible tariffs
08/17	R-2017-2595853	PA	AK Steel	Pennsylvania American Water Co.	Cost and revenue allocation, rate design
8/17	17-3112-INV	VT	Vt. Dept. of Pubic Service	Green Mountain Power	Return on equity, cost of debt, weighted cost of capital
9/17	4220-UR-123	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity, cost of short-term debt
12/17	2017-000321	KY	Office of the Attorney General	Duke Energy Kentucky, Inc.	Return on equity

Exhibit No. ___(RAB-2)



DUKE ENERGY.

Fall 2017 Investor Meetings

Our investor proposition

DUK LISTED NYSE

A SOLID LONG-TERM HOLDING

4.0%
DIVIDEND YIELD[1] WITH DIVIDEND **GROWTH COMMITMENT**[2]

~8-10%
ATTRACTIVE RISK-ADJUSTED **TOTAL SHAREHOLDER RETURN**[3]

4-6%
HIGHLY ACHIEVABLE **EPS GROWTH THROUGH 2021**[4]

SUPPORTED BY THE STRENGTH OF OUR BALANCE SHEET

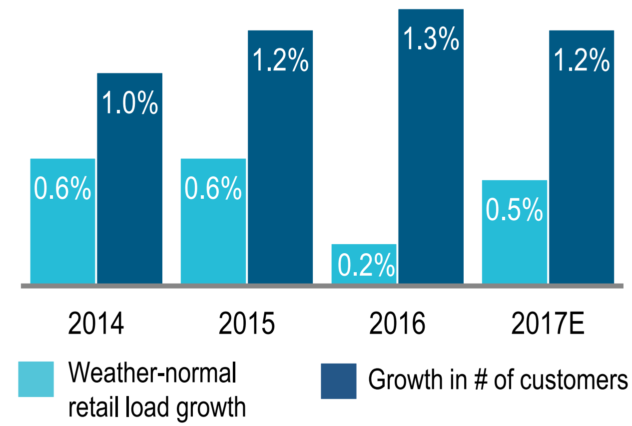
(1) *As of Oct. 31, 2017*
(2) *4-6% dividend growth subject to approval by the Board of Directors*
(3) *Total shareholder return proposition at a constant P/E ratio*
(4) *Based on adjusted diluted EPS off the midpoint of the original 2017 guidance range of $4.50-$4.70*

Managing regulatory lag to earn our allowed ROEs

EARNING ALLOWED ROEs WITH **NO SIGNIFICANT RATE CASES** SINCE 2013

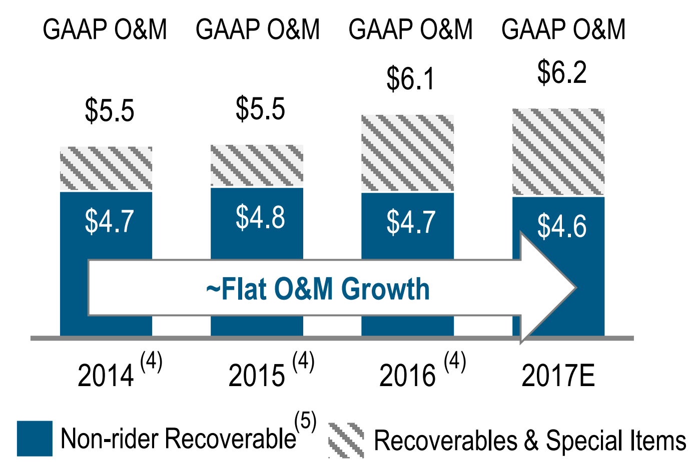
REGULATORY LAG MITIGATED BY **CUSTOMER GROWTH,** FOCUSED **COST MANAGEMENT** EFFORTS AND **WHOLESALE EXPANSION**

CUSTOMER GROWTH AND VOLUME TRENDS(1)

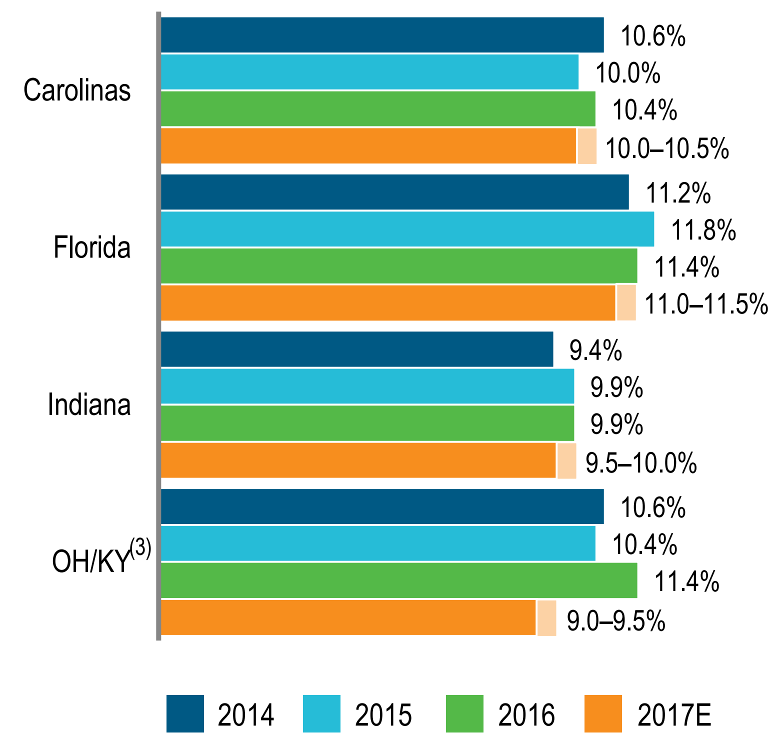


O&M COST MANAGEMENT(1)

($ IN BILLIONS)



ADJUSTED BOOK ROEs(1,2)



(1) 2017 assumptions as originally discussed on the Fourth Quarter 2016 Earnings Review and Business Update on Feb. 16, 2017

(2) Adjusted book ROEs exclude special items and are based on average book equity less Goodwill. Adjusted ROEs also include wholesale and are not adjusted for the impacts of weather. Regulatory ROEs will differ from Adjusted Book ROEs

(3) Combined electric and gas utilities

(4) Excludes Midwest Generation Business O&M (sold in April 2015), Latin American Generation Business (sold in December 2016)

(5) Excludes Piedmont Natural Gas, added beginning October 2016, to show trend

Access to capital – 2017 long-term debt financing activity

Amount ($ in millions)	Entity	Date Issued	Credit Ratings (M/S&P, unless otherwise noted)	Term	Type	Rate
$650	DE Florida	January 2017	A1/A	10 Year	First Mortgage Bond	Fixed – 3.200%
$250	DE Florida	January 2017	A1/A	3 Year	First Mortgage Bond	Fixed – 1.850%
$100	DE Ohio	March 2017	A2/A	29.2 Year(1)	First Mortgage Bond	Fixed – 3.70%
$587	Texoma Wind	February 2017	BBB-(2)	17.4 Year(3)	Secured	Fixed – 4.12%
$420	Holdco(4)	April 2017	N/A	8 Year	Senior Notes	Fixed – 3.364%
$330	Holdco(4)	June 2017	Baa1/BBB+	3 Year	Senior Notes	Fixed – 2.100%
$270(5)	Holdco	June 2017	N/A	3 Year	Revolving Credit Facility	Floating
$125(6)	Piedmont	June 2017	N/A	1.5 Year	Term Loan	Floating
$233	High Noon Solar	August 2017	BBB-(2)	19.4 Year(3)	Secured	Fixed – 4.11%
$500	Holdco	August 2017	Baa1/BBB+	5 Year	Senior Notes	Fixed – 2.400%
$750	Holdco	August 2017	Baa1/BBB+	10 Year	Senior Notes	Fixed – 3.150%
$500	Holdco	August 2017	Baa1/BBB+	30 Year	Senior Notes	Fixed – 3.950%
$300	DE Progress	September 2017	Aa3/A	3 Year	First Mortgage Bond	Floating
$500	DE Progress	September 2017	Aa3/A	30 Year	First Mortgage Bond	Fixed – 3.600%
$30	DE Kentucky	September 2017	N/A	12 Year	Debentures	Fixed – 3.35%
$30	DE Kentucky	September 2017	N/A	30 Year	Debentures	Fixed – 4.11%
$30	DE Kentucky	September 2017	N/A	40 Year	Debentures	Fixed – 4.26%
$125(7)	Piedmont	September 2017	N/A	1.5 Year	Term Loan	Floating

(1) Re-opener of $250 million 3.70% first mortgage bonds originally issued in June 2016 and due 2046
(2) As rated by Kroll Bond Rating Agency, Inc.
(3) Notes are amortizing, represents final year of maturity
(4) Issuance privately placed
(5) Amount drawn on a $1 billion revolving credit facility
(6) First draw on $250 million term loan
(7) Second draw on $250 million term loan

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17
Alliant Energy	High Price ($)	42.190	41.660	43.230	43.690	43.970	45.550
	Low Price ($)	40.160	39.360	40.500	41.160	41.050	42.880
	Avg. Price ($)	41.175	40.510	41.865	42.425	42.510	44.215
	Dividend ($)	0.315	0.315	0.315	0.315	0.315	0.315
	Mo. Avg. Div.	3.06%	3.11%	3.01%	2.97%	2.96%	2.85%
	6 mos. Avg.	2.99%					
Ameren Corp.	High Price ($)	57.210	56.670	60.790	60.910	62.140	64.890
	Low Price ($)	54.380	53.540	56.160	57.560	57.670	61.480
	Avg. Price ($)	55.795	55.105	58.475	59.235	59.905	63.185
	Dividend ($)	0.440	0.440	0.440	0.440	0.440	0.440
	Mo. Avg. Div.	3.15%	3.19%	3.01%	2.97%	2.94%	2.79%
	6 mos. Avg.	3.01%					
Black Hills	High Price ($)	72.020	70.800	71.010	70.970	69.790	65.710
	Low Price ($)	67.400	67.080	68.030	68.200	64.290	57.260
	Avg. Price ($)	69.710	68.940	69.520	69.585	67.040	61.485
	Dividend ($)	0.445	0.445	0.445	0.445	0.445	0.475
	Mo. Avg. Div.	2.55%	2.58%	2.56%	2.56%	2.66%	3.09%
	6 mos. Avg.	2.67%					
CenterPoint Energy	High Price ($)	29.080	28.340	30.120	30.450	29.970	30.070
	Low Price ($)	27.350	26.980	27.610	28.900	28.600	28.200
	Avg. Price ($)	28.215	27.660	28.865	29.675	29.285	29.135
	Dividend ($)	0.268	0.268	0.268	0.268	0.268	0.268
	Mo. Avg. Div.	3.80%	3.88%	3.71%	3.61%	3.66%	3.68%
	6 mos. Avg.	3.72%					
Chesapeake Utilities	High Price ($)	77.750	77.600	81.100	81.950	82.150	86.350
	Low Price ($)	73.650	74.800	77.150	76.950	77.650	78.600
	Avg. Price ($)	75.700	76.200	79.125	79.450	79.900	82.475
	Dividend ($)	0.325	0.325	0.325	0.325	0.325	0.325
	Mo. Avg. Div.	1.72%	1.71%	1.64%	1.64%	1.63%	1.58%
	6 mos. Avg.	1.65%					
CMS Energy Corp.	High Price ($)	48.370	47.020	48.910	49.110	48.920	50.850
	Low Price ($)	46.020	45.340	45.980	45.920	45.820	47.760
	Avg. Price ($)	47.195	46.180	47.445	47.515	47.370	49.305
	Dividend ($)	0.333	0.333	0.333	0.333	0.333	0.333
	Mo. Avg. Div.	2.82%	2.88%	2.81%	2.80%	2.81%	2.70%
	6 mos. Avg.	2.81%					
Consolidated Edison	High Price ($)	85.130	82.980	84.920	86.160	86.330	89.580
	Low Price ($)	80.670	80.040	82.040	80.020	80.260	85.270
	Avg. Price ($)	82.900	81.510	83.480	83.090	83.295	87.425
	Dividend ($)	0.690	0.690	0.690	0.690	0.690	0.690
	Mo. Avg. Div.	3.33%	3.39%	3.31%	3.32%	3.31%	3.16%
	6 mos. Avg.	3.30%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17
Dominion Energy	High Price ($)	81.650	77.570	80.670	79.950	82.130	84.340
	Low Price ($)	76.170	75.400	76.560	76.230	75.750	80.010
	Avg. Price ($)	78.910	76.485	78.615	78.090	78.940	82.175
	Dividend ($)	0.755	0.755	0.755	0.755	0.755	0.770
	Mo. Avg. Div.	3.83%	3.95%	3.84%	3.87%	3.83%	3.75%
	6 mos. Avg.	3.84%					
DTE Energy Co.	High Price ($)	111.350	108.000	112.580	113.710	113.270	116.210
	Low Price ($)	105.130	104.190	106.160	106.210	106.210	109.580
	Avg. Price ($)	108.240	106.095	109.370	109.960	109.740	112.895
	Dividend ($)	0.825	0.825	0.825	0.825	0.825	0.825
	Mo. Avg. Div.	3.05%	3.11%	3.02%	3.00%	3.01%	2.92%
	6 mos. Avg.	3.02%					
Duke Energy Corp.	High Price ($)	87.490	85.330	87.950	88.400	88.640	91.800
	Low Price ($)	83.590	82.720	84.650	83.400	83.520	87.560
	Avg. Price ($)	85.540	84.025	86.300	85.900	86.080	89.680
	Dividend ($)	0.855	0.855	0.890	0.890	0.890	0.890
	Mo. Avg. Div.	4.00%	4.07%	4.13%	4.14%	4.14%	3.97%
	6 mos. Avg.	4.07%					
Eversource Energy	High Price ($)	63.340	61.560	63.670	64.190	62.840	66.150
	Low Price ($)	60.520	59.550	60.370	60.010	59.590	61.980
	Avg. Price ($)	61.930	60.555	62.020	62.100	61.215	64.065
	Dividend ($)	0.475	0.475	0.475	0.475	0.475	0.475
	Mo. Avg. Div.	3.07%	3.14%	3.06%	3.06%	3.10%	2.97%
	6 mos. Avg.	3.07%					
Exelon Corp.	High Price ($)	37.440	38.500	38.780	38.500	40.380	42.670
	Low Price ($)	35.800	35.370	37.250	36.630	37.550	39.470
	Avg. Price ($)	36.620	36.935	38.015	37.565	38.965	41.070
	Dividend ($)	0.328	0.328	0.328	0.328	0.328	0.328
	Mo. Avg. Div.	3.58%	3.55%	3.45%	3.49%	3.37%	3.19%
	6 mos. Avg.	3.44%					
Fortis	High Price ($)	47.060	45.660	46.430	45.800	47.780	48.730
	Low Price ($)	44.420	43.980	45.060	44.010	44.450	46.530
	Avg. Price ($)	45.740	44.820	45.745	44.905	46.115	47.630
	Dividend ($)	0.400	0.400	0.400	0.400	0.400	0.425
	Mo. Avg. Div.	3.50%	3.57%	3.50%	3.56%	3.47%	3.57%
	6 mos. Avg.	3.53%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17
MGE Energy	High Price ($)	68.600	68.700	67.200	66.500	68.100	67.700
	Low Price ($)	63.800	61.800	62.010	63.200	63.800	63.630
	Avg. Price ($)	66.200	65.250	64.605	64.850	65.950	65.665
	Dividend ($)	0.308	0.308	0.323	0.323	0.323	0.323
	Mo. Avg. Div.	1.86%	1.89%	2.00%	1.99%	1.96%	1.97%
	6 mos. Avg.	1.94%					
NorthWestern Corp.	High Price ($)	63.860	61.800	61.360	60.820	59.610	64.380
	Low Price ($)	60.940	57.580	57.690	56.870	56.440	58.460
	Avg. Price ($)	62.400	59.690	59.525	58.845	58.025	61.420
	Dividend ($)	0.525	0.525	0.525	0.525	0.525	0.525
	Mo. Avg. Div.	3.37%	3.52%	3.53%	3.57%	3.62%	3.42%
	6 mos. Avg.	3.50%					
Public Svc. Enterprise Gp.	High Price ($)	45.800	45.360	47.470	47.010	49.700	53.200
	Low Price ($)	42.790	41.670	44.730	45.050	46.050	49.170
	Avg. Price ($)	44.295	43.515	46.100	46.030	47.875	51.185
	Dividend ($)	0.430	0.430	0.430	0.430	0.430	0.430
	Mo. Avg. Div.	3.88%	3.95%	3.73%	3.74%	3.59%	3.36%
	6 mos. Avg.	3.71%					
Vectren Corp.	High Price ($)	62.790	60.240	67.170	68.300	68.840	69.580
	Low Price ($)	58.240	57.480	59.450	64.930	65.570	64.000
	Avg. Price ($)	60.515	58.860	63.310	66.615	67.205	66.790
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.450
	Mo. Avg. Div.	2.78%	2.85%	2.65%	2.52%	2.50%	2.70%
	6 mos. Avg.	2.67%					
WEC Energy Group	High Price ($)	64.370	63.500	65.710	67.200	68.030	70.090
	Low Price ($)	61.240	60.470	62.730	62.400	62.840	66.760
	Avg. Price ($)	62.805	61.985	64.220	64.800	65.435	68.425
	Dividend ($)	0.520	0.520	0.520	0.520	0.520	0.520
	Mo. Avg. Div.	3.31%	3.36%	3.24%	3.21%	3.18%	3.04%
	6 mos. Avg.	3.22%					
Xcel Energy Inc.	High Price ($)	48.500	47.700	49.700	50.560	49.830	52.220
	Low Price ($)	45.790	45.180	47.180	46.690	46.860	48.930
	Avg. Price ($)	47.145	46.440	48.440	48.625	48.345	50.575
	Dividend ($)	0.360	0.360	0.360	0.360	0.360	0.360
	Mo. Avg. Div.	3.05%	3.10%	2.97%	2.96%	2.98%	2.85%
	6 mos. Avg.	2.99%					
Monthly Avg. Dividend Yield		3.14%	3.20%	3.11%	3.10%	3.09%	3.03%
6-month Avg. Dividend Yield		3.11%					

Source: Yahoo! Finance

PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Yahoo! Finance
Alliant Energy	4.50%	6.00%	5.00%	6.20%	6.75%
Ameren Corp.	4.50%	6.00%	4.00%	6.70%	7.00%
Black Hills	5.00%	7.50%	5.00%	5.60%	4.26%
CenterPoint Energy	3.50%	6.00%	4.00%	5.50%	7.38%
Chesapeake Utilities	5.50%	8.00%	8.00%	6.00%	8.10%
CMS Energy Corp.	6.50%	6.50%	5.50%	6.50%	7.44%
Consolidated Edison	3.00%	2.50%	2.50%	3.00%	3.23%
Dominion Energy	9.00%	6.50%	2.00%	5.60%	3.64%
DTE Energy Co.	7.00%	6.00%	4.00%	6.00%	4.91%
Duke Energy Corp.	4.50%	4.50%	2.00%	4.00%	3.23%
Eversource Energy	6.00%	6.50%	4.00%	5.90%	5.91%
Exelon Corp.	5.50%	8.50%	4.50%	4.30%	0.84%
Fortis	6.00%	9.00%	3.00%	5.50%	5.50%
MGE Energy	4.00%	7.00%	6.50%	4.00%	4.00%
NorthWestern Corp.	5.00%	4.50%	4.00%	1.50%	2.25%
Pub Sv Enterprise Grp.	5.00%	1.00%	3.50%	2.70%	1.48%
Vectren Corp.	4.50%	6.50%	5.00%	5.70%	6.00%
WEC Energy Group	6.00%	6.00%	3.50%	5.30%	5.27%
Xcel Energy Inc.	6.00%	4.50%	3.50%	5.50%	5.50%
Averages	5.32%	5.95%	4.18%	5.03%	4.88%
Median Values	5.00%	6.00%	4.00%	5.50%	5.27%

Sources: Value Line Investment Survey, Sept. 15, Oct. 27, and Nov. 17, 2017
Yahoo! Finance growth rates retrieved November 27, 2017
Zacks growth rates retrieved November 27, 2017
Note: Yahoo! estimate for MGE Energy was used for Zacks' value, which was not available.
Note: Zacks estimates were used for Fortis' and Xcel's Yahoo! forecasts, which were not available

PROXY GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) Yahoo! Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.11%	3.11%	3.11%	3.11%	3.11%
Average Growth Rate	5.32%	5.95%	5.03%	4.88%	5.29%
Expected Div. Yield	3.20%	3.21%	3.19%	3.19%	3.20%
DCF Return on Equity	***8.52%***	***9.16%***	***8.22%***	***8.07%***	***8.49%***
Method 2:					
Dividend Yield	3.11%	3.11%	3.11%	3.11%	3.11%
Median Growth Rate	5.00%	6.00%	5.50%	5.27%	5.44%
Expected Div. Yield	3.19%	3.21%	3.20%	3.20%	3.20%
DCF Return on Equity	***8.19%***	***9.21%***	***8.70%***	***8.47%***	***8.64%***

PROXY GROUP
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.35%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.59%
4	Risk Premium	
5	(Line 1 minus Line 3)	6.76%
6	Comparison Group Beta	0.69
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	4.64%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.23%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.35%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.88%
4	Risk Premium	
5	(Line 1 minus Line 3)	7.47%
6	Comparison Group Beta	0.69
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.13%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.01%

PROXY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
June-17	2.54%
July-17	2.65%
August-17	2.55%
September-17	2.53%
October-17	2.65%
November-17	2.60%
6 month average	2.59%

Source: www.federalreserve.gov

5 Year Treasury Bond Data

	Avg. Yield
June-17	1.77%
July-17	1.87%
August-17	1.78%
September-17	1.80%
October-17	1.98%
November-17	2.05%
6 month average	1.88%

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	10.50%
Book Value	7.50%
Average	9.00%
Average Dividend Yield	0.86%
Estimated Market Return	9.90%
Value Line Projected 3-5 Yr.	
Median Annual Total Return	8.00%
Average Annual Total Return	9.60%
Average	8.80%
Average of Projected Mkt. Returns	9.35%

Source: Value Line Investment Survey for Windows retreived Nov. 30, 2017

Comparison Group Betas:	Value Line
Alliant Energy	0.70
Ameren Corp.	0.65
Black Hills	0.90
CenterPoint Energy	0.90
Chesapeake Utilities	0.70
CMS Energy Corp.	0.65
Consolidated Edison	0.50
Dominion Energy	0.65
DTE Energy Co.	0.65
Duke Energy Corp.	0.60
Eversource Energy	0.65
Exelon Corp.	0.70
Fortis	0.70
MGE Energy	0.75
NorthWestern Corp.	0.70
Pub Sv Enterprise Grp.	0.70
Vectren Corp.	0.75
WEC Energy Group	0.60
Xcel Energy Inc.	0.60
Average	0.69

PROXY GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.00%	12.00%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.00%	5.00%	
Historical Market Risk Premium	5.00%	7.00%	5.97%
Comparison Group Beta, Value Line	0.69	0.69	0.69
Beta * Market Premium	3.43%	4.81%	4.10%
Current 20-Year Treasury Bond Yield	2.59%	2.59%	2.59%
CAPM Cost of Equity, Value Line Beta	**6.02%**	**7.39%**	**6.69%**

Source: *2017 SBBI Yearbook, Stocks, Bonds, Bills, and Inflation*, Duff and Phelps; pp. 2-6, 6-17, 10-30

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's First Set Data Requests
Date Received: October 27, 2017

AG-DR-01-089

REQUEST:

Reference the Stipulation approved by the Commission in Case No. 2016-00152, paragraph 10, page 14, which states, "Duke Energy Kentucky commits that for any future 'major AMR or AMI meter investments, distribution grid investments for DA' [Distribution Automation] or 'SCADA or volt/var resources' that require a CPCN, the Company will include a detailed cost-benefit analysis similar to what was submitted in this case. " The Company is proposing a significant investment ($67 million over several years) for Rider DCI, "targeted undergrounding", in this case.

a. Provide a cost-benefit analysis for targeted undergrounding in accordance with the Company's commitment in Case No. 2016-00152, paragraph 10.
b. Identify the circuit/tap sections targeted for undergrounding for the first 3 years ($15 million) of the program.
c. Locate the circuit/tap sections targeted for undergrounding on a map.
d. For each circuit/tap section targeted, provide the length of undergrounding.
e. For each circuit/tap section targeted, provide the count of customers served by the section to be undergrounded.
f. For each circuit/tap section targeted, provide SAIDI and SAIFI data, both with and without Major Event Days.

g. For each circuit/tap section targeted, provide SAIDI and SAIFI data, both with and without Major Event Days.

h. Estimate the impact on Company-wide SAIDI and SAIFI, both with and without Major Event Days, from undergrounding these circuit/tap sections.

Include in your responses all workpapers, worksheets, calculations, estimates, assumptions, and other materials used to calculate the amounts.

RESPONSE:

a. Objection: Assumes facts not in evidence, and misstates and misconstrues the Company's prior commitment. Duke Energy Kentucky's Targeted Underground program does not fall under the investment categories referenced in the Stipulation and as approved by the Commission in Case No. 2016-00152. Targeted Underground is *not* a "major AMR or AMI meter investment," nor is it "a distribution grid investment for DA [Distribution Automation] or SCADA or volt/var resource[s] that requires a CPCN" as the Company agreed to in the Commission's April 13, 2016 Order in Case No. 2012-00428.

Notwithstanding the objection, and to the extent discoverable, the 10 year budget for the Targeted Underground program and associated line miles by year are provided as AG-DR-01-089(a)(1) Attachment. Reliability benefits of completing the candidate line miles identified through 2026 are provided as AG-DR-01-089(a)(2) Attachment for non-Major Event Days (MEDs) and as AG-DR-01-089(a)(3) Attachment for MEDs.

Duke's analysis to identify outlier overhead segments using previous ten years outage history was used to project MED event benefits. By using past MED outage data showing specific CI (customers interrupted), CMI (customer minutes of interruption) and outage events (total number) linked to specific device or equipment identifiers, we were able to perform analysis to look for correlations between those MED event devices and the proposed list of candidate targets for the Targeted Underground program.

That correlation analysis suggests that MED events we will see a 16% reduction in outage events post completion of the proposed TUG program and a 15-20% reduction in major event day duration depending on the severity of the MED event. These percentages represent the average experience over multiple events.

b. Duke Energy Kentucky has not yet selected specific circuit/tap sections to complete in the first 3 years of its Targeted Underground program. However, AG-DR-01-089(b)(1) Attachment contains information on candidate circuit segments that are being considered for prioritization to be deployed within the first 3 years of the program. AG-DR-01-089(b)(2) Attachment contains information on all the candidate circuit segments within the Company's 10-year scope for the Targeted Underground program.

c. AG-DR-01-089(c)(1) Attachment shows the location within Duke Energy Kentucky's service area of candidate line segments being considered for prioritization within the first three years of the Targeted Underground program. AG-DR-01-089(c)(2) Attachment shows the location within Duke

Energy Kentucky's service area of candidate line segments within the Company's ten-year scope for the Targeted Underground Program.

d. See response to AG-DR-01-089(b).

e. The attachments provided in response to AG-DR-01-089(b) provide the count of customers who have experienced an outage in the last ten years on each candidate section. Those attachments do not list the total customer count on those segments.

f. Duke Energy Kentucky does not have SAIDI and SAIFI data at the individual circuit section level.

g. See response to AG-DR-01-089(f).

h. See response to AG-DR-01-089(a).

PERSON RESPONSIBLE: Objection- Legal
Tony Platz

DEK Targeted Overhead/Underground Conversion	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027*	Total
Total	**$ -**	**$ 5,048,798**	**$ 5,048,798**	**$ 5,048,798**	**$ 8,078,077**	**$ 7,575,000**	**$ 7,575,000**	**$ 7,575,000**	**$ 10,100,000**	**$ 10,100,000**	**$ 66,149,471**
Capital	$ -	$ 4,998,810	$ 4,998,810	$ 4,998,810	$ 7,998,096	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 10,000,000	$ 10,000,000	**$ 65,494,526**
O&M	$ -	$ 49,988	$ 49,988	$ 49,988	$ 79,981	$ 75,000	$ 75,000	$ 75,000	$ 100,000	$ 100,000	**$ 654,945**

Unit Cost	$ 470,000										
Units (Miles)	0	11	11	11	17	16	16	16	21	21	141

[1] Targeted Underground benefits were calculated based on spend projections and line miles through end of 2026. 2027 budget amount was not known until the time of testimony development.

DEK	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2012-2016 Std Dev	80% CI
SAIFI Trend	0.70	0.61	0.52	0.51	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.16	0.21
MAX	0.91	0.82	0.72	0.72	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71		
MIN	0.49	0.40	0.31	0.30	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29		
Targeted Underground (TUG) SAIFI Savings	0.70	0.61	0.52	0.51	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50		
MAX	0.91	0.82	0.72	0.72	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71		
MIN	0.49	0.40	0.31	0.30	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29		

DEK	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2012-2016 Std Dev	80% CI
SAIDI Trend	97	94	91	88	86	83	80	77	75	72	69	66	7.06	9.06
MAX	106	103	100	98	95	92	89	86	84	81	78	75		
MIN	88	85	82	79	77	74	71	68	66	63	60	57		
TUG SAIDI Savings	97	94	91	88	84	81	77	73	69	65	61	60		
MAX	106	103	100	97	93	90	86	82	78	74	70	69		
MIN	88	85	82	79	75	71	68	64	60	56	52	51		

DEK	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027		2012-2016 Std Dev	80% CI
EVENTS Trend	3,365	3,263	3,160	3,057	2,955	2,852	2,749	2,646	2,544	2,441	2,338		204.98	262.79
MAX	3,628	3,525	3,423	3,320	3,217	3,115	3,012	2,909	2,806	2,704	2,601			
MIN	3,103	3,000	2,897	2,794	2,692	2,589	2,486	2,384	2,281	2,178	2,076			
TUG EVENTS Savings	3,365	3,263	3,160	3,000	2,840	2,680	2,491	2,302	2,113	1,924	1,707			
MAX	3,628	3,525	3,423	3,263	3,102	2,942	2,754	2,565	2,376	2,187	1,970			
MIN	3,103	3,000	2,897	2,737	2,577	2,417	2,228	2,039	1,850	1,662	1,444			

Public Service Commission of Wisconsin
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**WIEG RECOMMENDED REVENUE ALLOCATION
USING THE STAFF'S ADJUSTED REVENUE INCREASE**

Ex.-WIEG-Baudino-2

WIEG RECOMMENDED REVENUE ALLOCATION AT STAFF RECOMMENDED REVENUE INCREASE

	Current Revenues	NSPW Recommended Increase	WIEG Reallocation	WIEG Recommded Allocation	WIEG Recommded Increase at NSPW 3.5%	WIEG Recommended Allocation At Staff Incr.	WIEG Recommded Increase at Staff 1.6%
Residential	$ 251,588	$ 14,992	$ 432	$ 15,424	6.1%	$ 6,866.2	2.7%
Small C&I	$ 42,478	$ 2,332	$ 73	$ 2,405	5.7%	$ 1,070.6	2.5%
Medium C&I	$ 109,169	$ 1,513		$ 1,513	1.4%	$ 673.6	0.6%
Large General TOD	$ 198,711	$ 4,449		$ 4,449	2.2%	$ 1,980.6	1.0%
Peak Controlled TOD	$ 61,107	$ 1,036		$ 1,036	1.7%	$ 461.2	0.8%
DS-1	$ 550	$ 19		$ 19	3.5%	$ 8.5	1.5%
RTP	$ 24,852	$ 256	$ (505)	$ (249)	-1.0%	$ (249)	-1.0%
Public St. Lighting	$ 6,011	$ 75		$ 75	1.2%	$ 33.4	0.6%
Other Sales	$ 1,528	$ 32		$ 32	2.1%	$ 14.2	0.9%
Other Operating Revenue	$ 2,203	$ 32		$ 32	1.5%	$ 14.2	0.6%
Total Operating Revenue	$ 698,196	$ 24,736		$ 24,736	3.5%	$ 10,874	1.6%

EXCERPT FROM
ELECTRIC UTILITY COST ALLOCATION MANUAL
NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
JANUARY, 1992

EX.-WIEG-BAUDINO-3

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. **Account 364 - Poles, Towers, and Fixtures**

   - Determine the average installed book cost of the minimum height pole currently being installed.

   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. **Account 365 - Overhead Conductors and Devices**

   - Determine minimum size conductor currently being installed.

   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. **Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

   - Determine minimum size cable currently being installed.

   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.

   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. **Account 368 - Line Transformers**

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. **Account 369 - Services**

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. **Account 364 - Poles, Towers, and Fixtures**

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (I/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c cable. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

  - Determine the feet, investment, and average installed book cost per foot for I/c cables by size and type of cable.

  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

  - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.

  - Balance of cable investment is assigned to demand.

  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.

  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).

  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.

  - Multiply zero intercept cost by total number of line transformers to get customer component.

  - Balance of transformer investment is assigned to demand component.

  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

RESUME OF RICHARD A. BAUDINO

Docket 4220-UR-123

EX. – WIEG – BAUDINO - 1

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Director of Consulting, Consultant** - Responsible for consulting assignments in revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
Atmos Cities Steering Committee
Canadian Federation of Independent Businesses
CF&I Steel, L.P.
Cities of Midland, McAllen, and Colorado City
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group

Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject

Healthcare Council of the National Capital Area

Vermont Department of Public Service

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Richard A. Baudino
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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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of
Richard A. Baudino
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

**Expert Testimony Appearances
of
Richard A. Baudino
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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of
Richard A. Baudino
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR- 09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E- GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009- 2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010- 2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010- 2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010- 2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010- 2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010- 2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010- 2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011- 2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
08/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
08/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation
09/16	2016-00162	KY	Kentucky Office of the Attorney General	Columbia Gas of Ky.	Return on equity, cost of short-term debt
09/16	16-0550-W-P	WV	West Va. Energy Users Gp.	West Va. American Water Co.	Infrastructure Replacement Program Surcharge
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring fencing and other conditions for acquisition, service quality and reliability
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP and Sharyland Dist. and Transmission Services, LLC	Return on equity
02/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
03/17	10580	TX	Atmos Cities Steering Committee	Atmos Pipeline Texas	Return on equity, capital structure, weighted cost of capital
03/17	R-3867-2013	Quebec, Canada	Canadian Federation of Independent Businesses	Gaz Metro	Marginal Cost of Service Study

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
05/17	R-2017-2586783	PA	Philadelphia Industrial and Commercial Gas Users Gp.	Philadelphia Gas Works	Cost and revenue allocation, rate design, Interruptible tariffs
08/17	R-2017-2595853	PA	AK Steel	Pennsylvania American Water Co.	Cost and revenue allocation, rate design
8/17	17-3112-INV	VT	Vt. Dept. of Pubic Service	Green Mountain Power	Return on equity, cost of debt, weighted cost of capital

PICGUG Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2017-2586783
PHILADELPHIA GAS WORKS	:	

REBUTTAL TESTIMONY

AND EXHIBIT

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

PHILADELPHIA INDUSTRIAL AND COMMERCIAL GAS USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.

JUNE 2017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2017-2586783**
PHILADELPHIA GAS WORKS	:	

REBUTTAL TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Did you submit Direct Testimony in this proceeding?

A. Yes. I submitted Direct Testimony on behalf of the Philadelphia Industrial and Commercial Gas Users Group ("PICGUG").

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimonies of Mr. Jerome Mierzwa, witness for the Office of Consumer Advocate ("OCA"), Mr. Robert Knecht, witness for the Office of Small Business Advocate ("OSBA"), and Mr. Kokou Apetoh, witness for the Bureau of Investigation and Enforcement ("I&E"). My Rebuttal Testimony will focus on certain issues relating to the cost and revenue allocation proposals set forth in the Direct Testimony of each of these witnesses. For purposes of my Rebuttal Testimony in this case, my not addressing a particular issue in the Direct Testimony of these witnesses should not imply that I agree with or do not oppose that issue. My Rebuttal Testimony will focus instead on several major issues, which are discussed in the following sections.

<u>PGW Alternative Fuel Rate Proposal</u>

Q. Please summarize the positions of the OCA, the OSBA, and I&E on PGW's alternative fuel rate proposal for Rate IT customers.

A. Mr. Mierzwa accepted the Company's Rate IT proposal, but with two exceptions. First, the floor rate would be determined based on Mr. Mierzwa's recommended 31.6% increase to Rate IT. I will discuss the details of this proposed increase later in my testimony. Second, Mr. Mierzwa recommended shortening the implementation time for the negotiated rate proposal from PGW's proposed three years to one year from Commission approval of this proposal.

Mr. Knecht rejected PGW's Rate IT proposal. Instead, Mr. Knecht recommended a 52% revenue increase for Rate IT customers that would produce rates that would be a ceiling from which the Company and the Rate IT customers could negotiate downward. I will address the problems with Mr. Knecht's recommendation in a subsequent section of my testimony.

Mr. Apetoh did not address PGW's alternative fuel rate proposal for Rate IT.

Q. Please address Mr. Mierzwa's alternative fuel rate proposal for Rate IT customers.

A. Mr. Mierzwa's proposal would make PGW's unacceptable proposal for Rate IT even worse. I addressed in my Direct Testimony why the Commission should reject PGW alternative fuel rate proposal for Rate IT and those arguments apply to Mr. Mierzwa's proposal to cut the implementation period from three years to one year.

In addition, Mr. Mierzwa did not address whether Rate IT customers would be able to fully convert their facilities to substitute alternative fuel for PGW's natural gas service in the one year that he proposed. If Rate IT customers are not set up to convert their facilities into taking alternative fuels, then they do not actually have a viable alternative fuel option. Moreover, Rate IT customers would be facing substantial rate increases under Mr. Mierzwa's proposal with very little time to prepare for those increases. Mr. Bresser describes Temple University's situation in greater detail in his Rebuttal Testimony and explains that Temple could be facing a 500% rate increase under both Mr. Mierzwa's and Mr. Moser's Rate IT proposals. Mr. Mierzwa's 31.6% rate increase is only the minimum increase for Rate IT, with substantially higher increases likely based on the cost of alternative fuels.

Q. Did Mr. Mierzwa examine whether alternative fuels are actually viable for Rate IT customers?

A. No. Mr. Mierzwa simply accepted Mr. Moser's proposed IT alternative fuel rate with no independent analysis as to whether Rate IT customers would or even could convert to alternative fuels after the one-year transition period he proposed in his testimony. Mr. Mierzwa seems to accept Mr. Moser's suggestion that Rate IT customers can leave PGW's system and switch to the customers' alternative fuel systems without recognizing that Rate IT customers may have alternative fuel systems sized for only limited durations (*e.g.*, interruptions).

Q. Are alternative fuels an economically viable alternative to PGW's natural gas service?

A. No, in my opinion they are not. Recent advances in the extraction of shale gas have produced new and abundant supplies of natural gas, which has resulted in significantly lower natural gas prices relative to alternative fuels. Mr. Moser cited the publication entitled *Annual Energy Outlook 2017* published by the United States Energy Information Administration ("EIA") in his Direct Testimony and showed that the cost of alternative fuels (propane and fuel oil) are significantly higher than natural gas and the EIA projects this trend to continue far into the future. Rebuttal Table 1 below presents the projected MMBtu costs for natural gas, propane, and distillate fuel oil for commercial and industrial sectors from the EIA's report.

Rebuttal Table 1

Energy Price Comparison ($/MMBtu)

	2018	2020	2025
Commercial:			
Propane	$15.55	$15.54	$16.15
Distillate Fuel Oil	$17.78	$18.91	$20.37
Natural Gas	$8.42	$9.65	$10.14
Industrial:			
Propane	$12.69	$12.68	$13.41
Distillate Fuel Oil	$17.86	$19.15	$20.80
Natural Gas	$4.46	$5.32	$5.48

Rebuttal Table 1 clearly shows that neither propane nor fuel oil are economically viable alternatives to natural gas for the foreseeable future.

Q. Since alternative fuels are not economically viable for Rate IT customers, does either Mr. Mierzwa's proposal or PGW's original proposal make any sense?

A. No. With alternative fuels priced so far above natural gas, there is no basis whatsoever for pricing Rate IT based on the cost of alternative fuels. Neither fuel oil nor propane are economically viable alternatives to natural gas.

Moreover, both proposals would inflict serious economic harm on the customers taking service under Rate IT. They would result in massive and totally unjustified rate increases for Rate IT customers. The Commission must take into consideration the huge economic burdens on the businesses and other customers, such as Temple University, that would be inflicted from PGW's and the OCA's alternative fuel rate proposals for IT customers. For the sake of the public interest, I strongly and unequivocally recommend the Commission reject any alternative fuel rate proposal for Rate IT.

Q. On page 27 of his Direct Testimony, Mr. Mierzwa testified that his revenue allocation "moderates" the increase proposed by PGW. Do you agree with his statement?

A. No. Mr. Mierzwa's recommended revenue allocation merely lowered the floor rate under PGW's proposal but left the ceiling rate unchanged. Thus, PGW could impose the same increase to Rate IT customers regardless of Mr. Mierzwa's recommendation. If, for example, the cost of alternative fuel would allow PGW to impose a 100% rate increase to Rate IT customers, PGW could do so under either Mr. Moser's or Mr. Mierzwa's proposal. Given Mr. Mierzwa's agreement with the rest of PGW's alternative fuel rate proposal, this is not rate moderation.

<u>Class Cost of Service Studies</u>

Q. Briefly summarize the positions of the witnesses with respect to class cost of service studies ("CCOSS").

A. Messrs. Apetoh and Mierzwa support the Peak and Average ("P&A") approach to classifying and allocating distribution mains in their recommended class cost of service studies ("CCOSS"). In these studies, class contribution to peak demand and average demands, or throughput, are each weighted 50%. Mr. Knecht developed a CCOSS based on his formulation of an average and excess ("A&E") approach to the classification and allocation of distribution mains.

Q. Do you agree with the P&A approach to allocating distribution mains in Philadelphia Gas Works' ("PGW") CCOSS?

A. No, I do not. For the reasons I stated in my Direct Testimony, the P&A CCOSS method is not appropriate due to the large amount of fixed distribution main cost that is classified and allocated based on throughput.

Q. On page 7, line 8 through page 9, line 10 of his Direct Testimony Mr. Mierzwa provides hypothetical examples that are intended to support his premise that distribution mains should not be classified and allocated based on the number of customers. Please respond to this portion of Mr. Mierzwa's Direct Testimony.

A. Mr. Mierzwa's simple examples do not refute the use of number of customers in classifying and allocating distribution mains costs to customers.

Mr. Mierzwa testified on page 7, lines 11 through 13 that mains are not sized based on the number of customers, but on the loads placed on the mains. I agree with

Mierzwa that mains are indeed sized based on loads, and I would go further to point out that the loads are based on the peak demands placed on the mains. This is especially important given peak winter demands placed on those mains. However, the number of customers connected to the distribution main system will also drive a portion of the Company's investment in mains. I described why a portion of distribution mains is related to the number of customers more fully in my Direct Testimony.

With respect to the example Mr. Mierzwa provided on page 9, lines 1 through 10, he confused the footage of distribution mains with the cost of distribution mains. Classifying and allocating distribution mains based on the number of customers does not allocate any particular number of feet of distribution mains to each customer regardless of size. Rather, it allocates the customer-related portion of total distribution main costs to customers based on the number of customers. This is the way other customer-related costs are allocated to customer classes. Mr. Mierzwa's example missed the point with respect to the customer-related portion of PGW's distribution mains costs.

Q. On page 14, lines 23 through 25 of his Direct Testimony, Mr. Mierzwa testified that "PGW cannot meet its customers' annual gas demands with a system capability any smaller than 204,878 Mcf" per day. Please respond to Mr. Mierzwa's testimony.

A. I do not agree with Mr. Mierzwa. The average daily demand figure he calculated does not properly show the difference between the design day peak and the average usage in the off-peak periods. Please refer to Rebuttal Table 2 below, in which I present a comparison of monthly sendout for January 2018, a peak winter month, and June 2018, the lowest consumption off-peak month.

Rebuttal Table 2
Monthly Mcf Sendout Comparison

	(1) Jan 2018	(2) June 2018	(3) Jan. as Multiple of June
Residential Heat	7,271,558	680,364	10.69
Commercial Heat	1,704,090	281,306	6.06
Municipal Heat	182,159	10,533	17.29
Total System	12,774,383	3,054,088	4.18

This comparison shows the large differences between peak month consumption and off-peak consumption for the heating classes and PGW's total system. The multiple for the Residential class is 10.69, which means that January peak month consumption is almost 11 times greater than off-peak consumption. For the system, the multiple is 4.18 times greater in the peak month.

The average daily consumption for the system in June is 101,803 Mcf. This is substantially less than the average daily consumption of 204,878 Mcf presented by Mr. Mierzwa. This comparison shows that average demand does vary substantially by month and that, by far, the highest monthly demands occur during the winter heating season. This also demonstrates that there is substantial excess capacity on the system during off-peak months.

In my opinion, Mr. Mierzwa has made a series of unsupported and conclusory statements in support of using average demands to classify and allocate distribution mains costs. He presented no concrete analysis that shows PGW considers annual throughput or demands in the design and construction of its distribution mains system. The Commission should reject the use of annual throughput and/or annual demands in PGW's CCOSS.

Q. Based on his analysis of the cost per foot of smaller and larger mains, Mr. Mierzwa concluded on page 19, lines 9 through 13, that "well less than half of distribution mains costs are associated with meeting elevated peak demand." Do you agree with Mr. Mierzwa's conclusion?

A. No. Mr. Mierzwa merely demonstrated economies of scale in the cost of distribution mains. Mr. Mierzwa even pointed this out on page 17, line 21 through page 18, line 2. However, economies of scale related to increasingly larger pipe sizes have no relevance with respect to how the total cost of distribution mains is classified and allocated. Rather, it is the overarching importance of meeting peak winter demands of PGW's customers and connecting those customers to the distribution system that should be reflected in the Company's CCOSS, not average demands and/or throughput.

Q. Did you compare the results of the P&A CCOSS and PGW's recommended CCOSS?

A. Yes. Rebuttal Table 3 below compares the results of the two studies (*i.e.*, OCA and I&E use of the P&A method versus PGW's usage of the Customer/Demand method).

The Table shows the amounts that each class' current revenues are either over or under the allocated cost to serve each class.

Rebuttal Table 3
CCOSS Results Comparison
Current Rev. Over (Under) Requirements

	P&A CCOSS	PGW CCOSS
Residential	$(52,256)	$(67,718)
Commercial	$(9,931)	$2,536
Industrial	$(906)	$226
PHA GS	$(259)	$(272)
Municipal/PHA	$(3,230)	$(1,273)
NGVS	$(8)	$1
Interrupt. Sales	$(15)	$(17)
GTS/IT	$(2,509)	$(2,598)
Total	$(69,113)	$(69,115)

The results are quite similar for GTS/IT customers. The largest shift occurs in the Commercial class, which shows a significant deficit in the P&A study compared to a significant surplus in PGW's study.

Q. Why are the results so similar for GTS/IT in both studies?

A. The P&A CCOSS weights the commodity portion of the mains allocator at 0% for GTS/IT. Neither Mr. Apetoh nor Mr. Mierzwa explained the reason for this. However, given the fact that IT customers are interruptible, it is appropriate to make an allowance in the allocation of mains such that IT is not given a full share of the P&A allocation factor in the CCOSS. This may be because IT customers can be interrupted and do not receive firm service from the Company.

Q. Does PGW's demand allocator for mains properly reflect cost responsibility for Rate IT customers?

A. No. PGW's demand allocator for main assumes that Rate IT customers will fully contribute to demands during the design day. As such, Rate IT customers are assigned demand-related distribution mains costs on the same basis as firm service customers. This is not the proper way to treat interruptible customers with respect to the allocation of mains because they would likely be interrupted on the design day, whereas firm service customers would not be interrupted. PGW also saves on distribution system costs thanks to the existence of interruptible customers taking service under Rate IT. Thus, Rate IT receives too much cost responsibility for distribution mains in both PGW's CCOSS and the P&A CCOSS relied upon by Mr. Apetoh and Mr. Mierzwa.

Q. Briefly describe the A&E CCOSS that Mr. Knecht recommends.

A. Mr. Knecht began the discussion of his recommended CCOSS on page 31 of his Direct Testimony. Mr. Knecht utilized an average and excess allocation factor for all customer classes, including separate factors for Rates IT and GTS. Mr. Knecht directly assigned mains to the GTS class that were identified with those customers. Mr. Knecht did not allocate a portion of the remaining distribution mains to GTS customers. Mr. Knecht also allocated costs associated with production and storage to GTS and IT customers using a 50/50 allocation of firm demand and total demand. In making this allocation, Mr. Knecht noted on page 32, lines 6 through 8 of his Direct Testimony that "it is only reasonable that interruptible customers who similarly benefit from these costs should be assigned some reasonable share."

Mr. Knecht also made other revisions to PGW's CCOSS, which he explains on page 32, line 26 through page 39, line 16. Among these changes is assigning Universal Service Costs to the Residential class.

Q. What is the amount of net distribution main plant that is allocated or assigned to GTS customers in Mr. Knecht's CCOSS?

A. The value of the directly assigned net distribution main plant assigned to the Rate GTS class in Mr. Knecht's CCOSS is $0. Mr. Knecht limited his allocation of distribution main plant to only directly assigned plant because, according to Mr. Knecht on page 30 of his Direct Testimony, PGW is able to identify specific mains facilities used to serve GTS customers. However, this directly assigned plant is fully depreciated. As a result, GTS customers have no distribution mains cost in their allocated cost to serve in Mr. Knecht's CCOSS.

Mr. Knecht's CCOSS assumes that GTS customers are not served by or otherwise interconnected with PGW's interconnected distribution system.

Q. What was Mr. Knecht's basis for excluding GTS customers from any allocation of PGW's distribution main system?

A. According to Mr. Knecht's response to PICGUG to OSBA-1-4, it was his understanding from past PGW proceedings that the mains plant used to serve GTS customers was identifiable and the full costs could be directly assigned. Mr. Knecht could not provide any studies, documentation, work papers or other materials showing that GTS customers are not part of PGW's integrated distribution system. Please refer to my Rebuttal Exhibit ____(RAB-1R) for Mr. Knecht's complete response.

Q. Have you conducted additional discovery on this issue?

A. Yes. PICGUG issued additional discovery to PGW regarding the issue of whether GTS customers are served by PGW's interconnected distribution system. In its response to PICGUG-V-1, the Company indicated that two of the three GTS customers included in its CCOSS are served on a separate individual gas main that is not part of PGW's distribution system. It is my understanding that this is why PGW did not include these customers in the distribution main allocation factor in its CCOSS.

In my view, PGW did not provide the necessary evidence or support that these two GTS customers do not receive any benefits or service from the Company's integrated distribution system. PICGUG issued another set of follow-up discovery on this issue. The Company's responses are not due until after the submission of Rebuttal Testimony. If the Company's responses have any effect on my own revenue allocation recommendation to the Commission, I will address it in my Surrebuttal Testimony.

Q. Mr. Baudino, please present your conclusions regarding Mr. Knecht's recommended A&E CCOSS.

A. Mr. Knecht's recommended CCOSS should be rejected by the Commission. It treats Rate IT customers as if they are receiving firm service, which they are not. Rate IT customers are interruptible, and simply because Rate IT has had one interruption in 20 years does not suddenly warrant treating it like firm service. I thoroughly discussed the reasons in my Direct Testimony as to why Rate IT customers should not be allocated costs as if they take firm service and I need not repeat them here.

However, they apply with equal force to the overall approach taken by Mr. Knecht in this proceeding.

Mr. Knecht's allocation of production and storage costs to Rate IT customers is particularly objectionable since these facilities are used to serve firm service customers, not interruptible transportation customers. PGW's CCOSS did not even allocate these costs to Rate IT, which is entirely appropriate. PGW's production and storage facilities were not designed to serve interruptible loads. As I pointed out on page 16 of my Direct Testimony, PGW explained that if Rate IT customers took firm service, the Company would need to invest in additional distribution system infrastructure, including LNG capability. Since PGW does not include Rate IT customers in its design day planning or its design day demand allocator, it logically would not invest in LNG and storage facilities to serve interruptible customers.

This is also the case for distribution mains, which Mr. Knecht allocated to Rate IT as if it were firm service. This is simply incorrect and results in a radical and unwarranted shift in costs to Rate IT.

Q. Did Mr. Knecht recommend that Rate IT be changed so that it is no longer interruptible?

A. No. Based on my understanding of Mr. Knecht's Direct Testimony, he did not recommend any changes to the Rate IT tariff language with respect to customers being interruptible or having to maintain alternative fuel capability. Thus, Mr. Knecht's CCOSS allocates costs to Rate IT as if it were a firm service class, but retains the interruptible characteristics of the current tariff. This results in the worst of all possible worlds for Rate IT customers.

Q. How much did Mr. Knecht's CCOSS affect cost responsibility for Rate IT customers?

A. Mr. Knecht's CCOSS has a drastic effect on Rate IT customers. Mr. Knecht's CCOSS would result in an increase of $24.077 million to Rate IT, compared to PGW's increase to full cost of service of $2.598 million for the combined GTS/IT class. This represents an unwarranted increase of $21.479 million in cost responsibility for Rate IT customers compared to PGW's CCOSS and would result in a 220% rate increase for IT customers, which I will show in the next section of my Rebuttal Testimony.

Q. Mr. Knecht recommended that universal service costs be assigned to the residential class. Do you agree with this recommendation?

A. Yes. These costs are incurred by the Company for residential customers and should be allocated to the Residential class. Non-residential customers bear no responsibility for these costs and should not be allocated any of these costs in the CCOSS.

Q. Mr. Knecht's recommended CCOSS also presented results for GTS customers as a separate class. What are your comments with respect to the CCOSS results for the GTS class?

A. Although I disagree with Mr. Knecht's A&E CCOSS, even with zero cost of distribution mains in the CCOSS, the GTS class showed a revenue shortfall of $2.438 million. Since the GTS rates are negotiated, Mr. Knecht did not allocate any increase to the GTS class. This, in effect, shows that the rest of PGW's customers are paying for the revenue shortfall from the GTS rate class.

<u>**Class Revenue Allocation**</u>

Q. Please summarize the revenue allocation recommendations of Mr. Apetoh, Mr. Mierzwa, and Mr. Knecht with respect to Rate IT customers.

A. Rebuttal Table 4 below summarizes the respective revenue allocations to Rate IT customers made by Mr. Apetoh, Mr. Mierzwa, and Mr. Knecht.

Rebuttal Table 4
Rate IT Increase Comparison

	(1) COSS Increase To System Avg.	(2) % Increase	(3) Recommended Increase	(4) % Increase
I&E Recommendation	2,509	20.00%	2,570	20.99%
OCA Recommendation	2,509	20.00%	3,450	28.20%
PGW Recommendation	2,598	23.77%	5,500	50.33%
OSBA Recommendation	*24,077*	*220.10%*	*5,696*	*52.10%*

In reviewing Rebuttal Table 4, a few additional comments are necessary. First, Column (1) shows the increases required to bring Rate IT to the required cost of service revenue level in each witness' recommended CCOSS. Messrs. Apetoh and Mierzwa recommend the same CCOSS (*i.e*, the P&A methodology), so the required increase to the system average return is the same ($2.509 million); however, Messrs. Apetoh and Mierzwa diverge with respect to their proposed rate increases for Rate IT.

Mr. Apetoh's recommended increase is in keeping with the CCOSS results in that the COSS shows a 20% rate increase, and Mr. Apetoh proposes a 20.99% increase; however, Mr. Apetoh's proposed increase is actually understated since the increases are calculated based upon combined GTS and IT revenues. In other words, Mr. Apetoh's proposed increase assumes both GTS and IT customers would receive a 20.99% increase; however, because GTS customers have negotiated rates, only IT customers would bear the burden of any rate increase. As a result, Mr. Apetoh's proposed rate increase translates to an actual rate increase for Rate IT customers of 23.5%.

Mr. Mierzwa testified that he limited the increase to Rate IT to consider gradualism, but seemed to agree with PGW that the CCOSS did not capture the full cost responsibility for Rate IT customers. Specifically, Mr. Mierzwa's COSS shows the need for an increase to Rate IT of 20%; however, the OCA recommends a rate increase of 28.2%. Moreover, as with Mr. Apetoh's proposal, Mr. Mierzwa's proposal is understated since the increases are calculated based on combined GTS and IT revenues. As I stated in my Direct Testimony, GTS customers cannot have their negotiated rates increased in this proceeding. Therefore, the actual percentage increase to Rate IT that results from the OCA recommendation is 31.6%. As a result, Mr. Mierzwa's claims of gradualism do not seem to comport with this actual rate increase.

Conversely, Mr. Knecht utilized the A&E methodology, which showed a significant difference from the COSSs adopted by PGW, OCA, and I&E. Mr. Knecht, however, does not propose to utilize his COSS for purposes of revenue allocation, but rather, accepted the Company's recommended revenue increase. As a result, Mr. Knecht's proposed revenue increase of $5.696 million is substantially below the $24.077 million that would be required under his recommended CCOSS; however, Mr.

Knecht's proposed increase is slightly higher than PGW's recommendation of $5.5 million as set forth in Mr. Hanser's Direct Testimony.

Q. Please present your conclusion with respect to Mr. Apetoh's recommended revenue allocation.

A. Mr. Apetoh followed the results of the P&A CCOSS with respect to revenue allocation for Rate IT. Although I disagree with the P&A CCOSS, if the Commission adopts his recommended CCOSS, then I continue to recommend a system average increase for Rate IT consistent with my recommendation in my Direct Testimony.

Q. On page 24, line 13 of his Direct Testimony Mr. Apetoh recommended a $125 monthly customer charge for Rate IT. Please respond to Mr. Apetoh's recommendation.

A. I disagree with Mr. Apetoh's recommendation. As I described in my Direct Testimony, most of PGW's costs are fixed and, as such, should be collected more through fixed charges than through a volumetric charge based on consumption. Mr. Apetoh's recommendation goes in the opposite direction by significantly decreasing the current Rate IT customer charge.

Mr. Apetoh cited the Commission Order in Docket R-00038805 as a precedent for costs that may be included in the customer charge. I will not take issue with respect to how the Commission applies this Order to sales gas customers. However, for large transportation customers that do not have monthly demand charges, more of PGW's fixed costs must be collected through the fixed monthly customer charge. Collecting most of the Company's fixed costs through the volumetric rate tends to favor low load factor customers over high load factor customers, causing intra-class subsidies in Rate IT and with larger usage customers generally. Furthermore, the collection of less fixed costs in the volumetric rate contributes to revenue stability for the utility company, other things being equal.

Q. What is your recommendation with respect to the customer charge for Rate IT?

A. As I have already noted, I believe the PUC should approve a system average increase for Rate IT; however, in the event that the PUC decides different, and given the large recommended increases from the OCA and the OSBA in addition to PGW's large recommended increase, I have decided to modify my recommendation for increasing the customer charge for Rate IT customers. I believe this revised recommendation will better address any potential rate increase scenario.

First, my primary recommendation is that the Rate IT customer charge be increased at 1.5 times the average increase for Rate IT customers. For example, if the Commission orders a 10% increase for Rate IT, then the customer charge should be increased by 15%. This recommendation will ensure a reasonable increase to the customer charge and, at the same time, protect IT customers from excessive increases to the customer charge.

Second, consistent with the recommendation in my Direct Testimony, the customer charge for Rate IT should at a minimum be increased at an equal percentage to the overall increase for Rate IT customers. Thus, if the Commission orders a 10% increase in revenue for Rate IT, then the customer charge would then be increased by 10%. I recommend that the Commission adopt this recommendation if it orders an increase for Rate IT that is more than twice the system average rate increase. For example, if the Commission orders a system average revenue increase of 10% and a 20% increase for Rate IT, then both the customer and volumetric charges would be increased by the same percentage increase.

Q. On page 47, lines 4 through 7 of his Direct Testimony Mr. Apetoh described his recommended scale back of rates. Please comment on this proposal.

A. If the Commission accepts Mr. Apetoh's recommended revenue allocation, then this approach is reasonable. However, it is not reasonable with respect to the revenue allocation proposals from PGW, the OCA and the OSBA because of the excessive increases these parties recommend for Rate IT. Based upon my Rebuttal Testimony, though, the Commission should reject the increases recommended by these parties for Rate IT customers.

Q. What is your recommendation with respect to Mr. Mierzwa's revenue allocation to Rate IT?

A. I recommend the Commission reject Mr. Mierzwa's recommended revenue allocation to Rate IT. His recommendation does not follow the results of his recommended P&A CCOSS, which shows a much smaller increase for Rate IT/GTS. Mr. Mierzwa merely followed PGW's recommendation for a large increase to Rate IT on the basis that the CCOSS does not provide an adequate measure of Rate IT's cost responsibility. Mr. Mierzwa, however, provided the Commission with no guidance or analysis as to what exactly the cost responsibility should be for Rate IT. As such, like Mr. Hanser's proposed 50.33% increase to Rate IT, Mr. Mierzwa's 31.6% increase to Rate IT customers is untethered from the principle that rates should be based on costs to serve.

Q. What is your recommendation with respect to Mr. Knecht's recommended 52% revenue increase to Rate IT?

A. Mr. Knecht's recommendation should be rejected. Mr. Knecht's CCOSS is flawed and grossly inflates cost responsibility for the interruptible customers taking service under Rate IT. It also flagrantly violates the gradualism principle by subjecting Rate IT customers to a punitive and unjustified rate increase, which I strongly recommend the Commission reject.

Q. On page 45, line 12 through page 46, line 3 Mr. Knecht explained his reasoning behind the 52% increase. Please respond to his testimony on this point.

A. Mr. Knecht's justifications for violating the gradualism principle are wholly insufficient.

First, Mr. Knecht reasoned that customers who switched to Rate IT and received uninterrupted service did so with what he called a significant rate decrease. Therefore, the 52% increase was justified. Essentially, Mr. Knecht would punish Rate IT customers for taking interruptible service, being willing to agree to having alternate fuel capability, and being willing to be interrupted in accordance with a Commission approved tariff. This is no reasonable basis whatsoever for the violation of the gradualism principle.

Second, Mr. Knecht asserted that under his Rate IT proposal, customers could negotiate a lower rate if Mr. Knecht's proposed IT rates proved to be a hardship. I believe that this possibility is highly unlikely. This is because PGW would lose the Commission approved revenues from Rate IT customers if they were to negotiate a lower rate with the Company. Under Mr. Knecht's proposal there is no way for

PGW to make up lost revenues from negotiated rates that are lower than the tariffed IT rates he recommends. Rather than have its margins eroded from lost revenues from lower negotiated rates with Rate IT customers, it is highly likely that PGW would never agree to negotiate lower rates unless a customer were to go out of business and PGW would lose all revenues from the customer. Therefore, the remote possibility that a Rate IT customer could somehow negotiate a lower rate with PGW provides no basis for the extreme 52% increase imposed by Mr. Knecht.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-2017-2586783
	:	
PHILADELPHIA GAS WORKS	:	

REBUTTAL EXHIBIT

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

PHILADELPHIA INDUSTRIAL AND COMMERCIAL GAS USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.

JUNE 2017

PICGUG to OSBA-I-4

Please explain in detail why Mr. Knecht did not allocate a share of distribution mains, other than those that were directly assigned, to GTS customers in his recommended CCOSS.

a. Please provide any studies, documentation, work papers, and other materials that show that GTS customers are not part of PGW's integrated distribution mains system.

b. Please confirm that the net distribution mains plant allocated/assigned to GTS customers in Mr. Knecht's CCOSS is zero. If you disagree, please provide the amount of net distribution mains plant (gross plant less accumulated depreciation) that is allocated/assigned to GTS customers.

c. If net distribution mains plant allocated to GTS customers in Mr. Knecht's CCOSS is zero, please explain why this is a reasonable allocation of mains to GTS customers.

Response:

Based on my experience in PGW proceedings, it was my understanding that the mains plant used to serve GTS customers was all identifiable and the full costs could be directly assigned. If additional mains are needed to provide service to GTS customers, the mains allocator should be modified to do so. While the Company's responses are not definitive, the response to PICGUG-III-1 might be interpreted as implying that the mains allocator for GTS should reflect a relatively small demand from one customer. If that proves to be the case, I will update my analysis in surrebuttal testimony.

a. I have none. I relied on Company representations and past experience.

b. Confirmed. However, as shown at page 19 of Exhibit IEc-3, gross plant is assigned to the GTS rate class, and that contributes to "downstream" allocation factors for O&M and A&G. Thus, the directly assigned GTS plant does "attract" a set of other costs to the GTS rate class.

c. The Company indicates that the plant used to serve GTS customers is fully depreciated. While replacement cost concepts may sometimes be used in cost allocation analyses, my experience is that Pennsylvania utilities generally rely on book costs for allocating mains costs among rate classes.

PICGUG Statement No. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2017-2586783**
PHILADELPHIA GAS WORKS	:	

SURREBUTTAL TESTIMONY

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

PHILADELPHIA INDUSTRIAL AND COMMERCIAL GAS USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.

JUNE 2017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2017-2586783**
PHILADELPHIA GAS WORKS	:	

SURREBUTTAL TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Did you submit Direct and Rebuttal Testimony in this proceeding?

A. Yes. I submitted Direct and Rebuttal Testimony on behalf of the Philadelphia Industrial and Commercial Gas Users Group ("PICGUG").

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimonies of Mr. Moser and Mr. Hanser, witnesses for Philadelphia Gas Works ("PGW"), Mr. Jerome Mierzwa, witness for the Office of Consumer Advocate ("OCA"), Mr. Robert Knecht, witness for the Office of Small Business Advocate ("OSBA"), and Mr. Kokou Apetoh, witness for the Bureau of Investigation and Enforcement ("I&E"). As in my Rebuttal Testimony, I will focus on several major cost and revenue allocation issues, and PGW's Alternative Fuel Rate Proposal, which are discussed in the following sections.

<u>PGW Alternative Fuel Rate Proposal for Rate IT</u>

Q. On page 3, lines 5 through 13 of his Rebuttal Testimony, Mr. Moser testified that PGW's Rate IT proposal "would not generate more revenue from the Company overall." Is this correct?

A. No. PGW's Rate IT proposal provides that the Company's proposed 50% increase to Rate IT customers is only a starting point in terms of the revenues that would be generated from Rate IT customers. This 50% increase would collect PGW's proposed test year revenues from Rate IT, but the increase to IT customers would not stop there. The so-called "value-based" part of PGW's proposal would enable the Company to collect further increases from Rate IT customers over and above the test year level of revenues shown in Mr. Hanser's class cost of service study ("CCOSS"). Thus, Mr. Moser's Rate IT proposal would generate more revenues for the Company than the test year level of revenues, and those increased revenues will come from Rate IT customers.

Q. On page 3, lines 21 through 24 of his Rebuttal Testimony, Mr. Moser testified that "using only a cost-based rate created an incentive for customers to avoid taking firm service which is resulting in fewer and fewer transportation customers contributing to the overall costs of running the distribution system." Please respond to Mr. Moser's testimony on this point.

A. Cost-based rates by definition do not create incentives for customers to avoid paying their fair share of costs. Rather, cost-based rates are designed to collect each class' fair share of the utility company's costs to serve them. PGW's interruptible customers appropriately pay for a lower share of costs than firm service customers because they are willing and able to be interrupted and because they have alternative fuel capability to help them manage the interruptions. Cost-based rates for interruptible customers should be lower than those for equivalent firm service customers.

Q. On page 3, line 24 through page 4, line 8 of his Rebuttal Testimony, Mr. Moser explained why the Company should be allowed "to maximize the amount of revenue that can be achieved from interruptible customers." Please respond to this portion of Mr. Moser's Rebuttal Testimony.

A. Mr. Moser's reasons for "maximizing" the amount of revenue that can be collected from Rate IT customers are unreasonable and should be rejected by the Commission. Mr. Moser's view of revenue maximization, regardless of the actual cost to serve, as well as his disregard for the potentially harmful rate impact on IT customers, is highly objectionable. The Commission should not allow PGW to charge exorbitant rates to IT customers in the name of deferring the need for future base rate relief for other customers. Such an approach would cause Rate IT customers to subsidize the other customer classes. Moreover, the proper way for PGW to defer future rate proceedings is to prudently manage its costs so that all customers, both firm and interruptible, are assured of reliable service at the lowest possible costs to serve them.

The Commission should not allow PGW or any other Company it regulates to charge excessive rates to a particular customer class in order to defer rate increases for other customers. Such an approach violates appropriate ratemaking principles.

Q. On page 4, lines 15 through 20 of his Rebuttal Testimony, Mr. Moser claimed that Rate IT customers have competitive alternatives and that they could "leave the system tomorrow." Please respond to Mr. Moser's assertion.

A. Mr. Moser provided no basis for the statement that Rate IT customers have competitive alternatives to PGW's service and that they could "leave the system tomorrow" if they so desired. Both Mr. Moser and I have shown that the cost of alternative fuels is far greater than natural gas. The economics of alternative fuels do not support Mr. Moser's contention that Rate IT customers have any viable alternative to PGW's interruptible service or that they could or would leave the system tomorrow or any other day. Given the costs per MMBtu I presented in my Rebuttal Table 1, fuel oil and propane are not economic alternatives to natural gas and will not be economic for the foreseeable future. Distillate fuel oil is around four times the cost of natural gas on an MMBtu basis for industrial customers according to the United States Energy Information Administration's *Annual Energy Outlook 2017*, a source that Mr. Moser relied on in his testimony. Neither current nor forecasted alternative fuel costs support Mr. Moser's contention that Rate IT customers have economic alternatives to natural gas.

Q. On page 5, lines 11 through 13 of his Rebuttal Testimony, Mr. Moser claimed that, because IT customers have "competitive alternatives," PGW is "inherently incentivized to negotiate fair and reasonable rates." Please respond to Mr. Moser's testimony.

A. First, both Mr. Moser and I presented evidence that Rate IT customers do not have economic competitive alternatives to natural gas, so the first part of Mr. Moser's statement is clearly incorrect. Second, given the fact that Rate IT customers do not have economically viable alternatives to natural gas, there is no inherent incentive for PGW to negotiate fair and reasonable rates since those negotiated rates will be based on the costs of uneconomic alternative fuels and not based on PGW's costs to serve Rate IT customers.

Q. On page 5, line 25 through page 6, line 1 of his Rebuttal Testimony, Mr. Moser cited an alternative fuel rate that the Pennsylvania Public Utility Commission ("PPUC" or "Commission") approved for UGI Utilities, Inc. Please respond to this portion of Mr. Moser's testimony.

A. I recommend that the PPUC base its decision in this case on the merits of PGW's proposal, not on what the Commission decided for another, unrelated natural gas utility. The current economic environment clearly shows that the costs of alternative fuels are so far above the cost of natural gas that Rate IT customers do not have viable alternatives to PGW's interruptible natural gas service. Therefore, PGW's proposed alternative fuel proposal for Rate IT is ill timed, unreasonable, and should be rejected.

Q. On page 6, lines 10 through 20 of his Rebuttal Testimony, Mr. Moser took issue with your reference to the 2007 Commission Order that directed PGW to establish cost-based transportation rates. Please respond to Mr. Moser's testimony.

A. My testimony still stands with regard to prior Commission precedent addressing cost-based transportation rates. I note that Mr. Moser once again testified that the Commission has approved value of service pricing for interruptible customers "that have competitive alternatives." I have demonstrated very clearly that Rate IT customers do not have economically competitive alternatives to PGW's natural gas service. With this being the case, there is no reasonable support for PGW's proposed alternative fuel rate for IT customers in this case.

Q. On page 7, lines 4 through 17 of his Rebuttal Testimony, Mr. Moser disagreed with your contention that PGW's proposal would allow the Company to earn excess profits from Rate IT customers. Please respond to this portion of Mr. Moser's testimony.

A. Nothing in this portion of Mr. Moser's Rebuttal Testimony alters my position with respect to the fact that PGW's alternative rate proposal would allow the Company to earn excessive returns from Rate IT customers, much to their detriment. I continue to recommend that the Commission continue its practice of cost-based rates for IT customers and reject the so-called "value based pricing" approach proposed by Mr. Moser.

Q. On page 8, line 1 of his Rebuttal Testimony, Mr. Moser testified that the PICGUG witnesses do not contest the long-term pattern of no interruptions for Rate IT. Please respond to Mr. Moser's testimony.

A. Simply because PGW has not interrupted Rate IT customers frequently does not mean that Rate IT customers are not interruptible. Rate IT customers are, in fact, interruptible, have agreed to be interrupted, and have alternate fuel capability as a condition of their service. This arrangement is not the same as firm customers, and Rate IT customers should not be treated as firm service customers with respect to cost allocation and responsibility. I explained this more fully in my Direct Testimony and nothing in this portion of Mr. Moser's Rebuttal Testimony alters my position.

Q. On page 8, lines 21 through 24 of his Rebuttal Testimony, Mr. Moser testified that PGW could use a different model such as throughput and demand that would allocate far greater costs to Rate IT customers. Please respond to this portion of Mr. Moser's testimony.

A. Mr. Moser's testimony here seems to be at odds with Mr. Hanser's approach to the Company's CCOSS. If indeed PGW believed that cost responsibility should be based partly on throughput, then the Company could have filed a CCOSS based on classifying and allocating distribution mains based on both demand and throughput. However, Mr. Hanser was quite clear in both his Direct and Rebuttal Testimonies that distribution mains should be classified and allocated based on design day demand and the number of customers, not throughput. I agree with Mr. Hanser's approach in this regard, although allocating Rate IT customers a full share of distribution mains based on design day demand would likely overstate their cost responsibility given the fact that they are interruptible and that PGW does not plan for interruptible loads on the design day. In any event, Mr. Moser's testimony on this point is not even supported by Mr. Hanser.

Q. On page 9, lines 7 through 17 of his Rebuttal Testimony, Mr. Moser describes his view of the cost savings that IT customers provide to the system. He stated that "the only cost savings IT customers can reasonably claim are the costs that PGW would have to incur to have the capacity to serve them on PGW's design day." Please respond to Mr. Moser's testimony on this point.

A. Mr. Moser's view of the cost savings provided by IT customers is incomplete. I agree that the costs referenced by Mr. Moser in his testimony are saved by not providing firm service to IT customers. However, excluding IT loads on the design day should also include savings from the future expansion of PGW's distribution system. There are also other benefits to firm service customers from PGW's ability to interrupt IT customers for reliability reasons during peak winter load conditions, for example. Interruptible loads benefit all of PGW's customers in terms of lowering system expansion costs and enhancing system reliability.

Q. On page 9, lines 23 through 24 of his Rebuttal Testimony, Mr. Moser made the claim that large volume customers are inherently riskier because they have "competitive alternatives." Is this assertion correct?

A. No. I have demonstrated that IT customers do not have economic alternatives to PGW's natural gas service. Because this is the case, it is a virtual certainty that IT customers will not leave PGW's system to pursue alternative fuel options.

Q. On page 11, lines 4 through 15 of his Rebuttal Testimony, Mr. Moser responds to your testimony regarding UGI's interruptible tariff. Please respond to his testimony on this point.

A. First, I explained that simply because UGI had an alternative fuel rate tariff that had been in place for a number of years, that in and of itself is not an appropriate basis for the Commission to approve PGW's proposal for Rate IT, and I stand by that testimony. As I stated previously, PGW's proposal is ill timed and unreasonable given the current and forecasted prices of alternative fuels.

Second, I disagree with Mr. Moser's assertion that "Rate IT customers do not like the price that PGW charges for firm transportation service." As I stated in my Direct Testimony, PGW does not currently have a cost based firm transportation rate that is designed based on the characteristics of large commercial and industrial customers. I continue to maintain the recommendation in my Direct Testimony that PGW submit a cost based firm transportation rate for the customers in Rate IT.

Q. On page 12, lines 9 through 14 of his Rebuttal Testimony, Mr. Moser responded to Mr. Bresser's estimate of the additional costs faced by Temple University from PGW's proposed IT rate. Please respond to Mr. Moser's testimony on this point.

A. Mr. Bresser's testimony showed the full impact of PGW's proposal if Temple's rate was based on PGW's proposed firm transportation rate. However, even a movement to the midpoint of PGW's proposed "cost of service" rate and the firm transportation rate would be excessive and unreasonable. Referring to Mr. Bresser's Direct Testimony on page 8, the midpoint between PGW's proposed minimum rate for IT-C ($1.08/Dth) and the proposed maximum rate ($3.81/Mcf) is $2.45/Dth (not including conversion from Mcf to Dth). This $2.45/Dth rate compared to the current IT-C rate of $0.68/Dth ***represents an increase of 260% from the current IT-C rate.*** This exorbitant increase, which would very likely take place under Mr. Moser's proposal for Rate IT, is unreasonable by any principled standard of ratemaking. I continue to strongly recommend that the Commission categorically reject Mr. Moser's proposal for Rate IT customers.

Q. On pages 12 and 13 of his Rebuttal Testimony, Mr. Mierzwa continued to recommend the adoption of PGW's alternative rate proposal. Please respond to Mr. Mierzwa's testimony.

A. First, Mr. Mierzwa failed to evaluate whether Rate IT customers have viable alternatives to PGW's natural gas service. I have demonstrated that Rate IT customers do not have economic alternative fuel choices, and, thus, Mr. Mierzwa's testimony is not supported on this point.

Second, Mr. Mierzwa testified on page 13, lines 2 through 4 that adopting a policy of negotiating rates for IT service will likely reduce the alleged difference between IT revenues and the IT cost of service "more quickly than the traditional base rate setting." Rapidly escalating the rates for Rate IT customers is by no means a valid or reasonable basis for adopting PGW's proposal. It totally ignores the excessive rate increases to which IT customers would be subjected and thus violates the principle of gradualism. I doubt that Mr. Mierzwa would have recommended a similar approach to rate increases for the Residential class if this class was found to be far below its allocated cost to serve.

Moreover, I disagree with Mr. Mierzwa's view on cost responsibility for Rate IT. I will discuss this issue later in my Surrebuttal Testimony.

<u>Class Cost of Service Studies and Revenue Allocation</u>

Q. On page 11, Table 2-R of his Rebuttal Testimony, Mr. Mierzwa attempted to show that the per Mcf increases for Rate IT were less than those for the firm service classes and incorporate the concept of gradualism. Please respond to Mr. Mierzwa's testimony.

A. The per Mcf increases shown in Mr. Mierzwa's Table 2-R are irrelevant with respect to the principle of gradualism. Because a typical Rate IT customer consumes far more Mcfs than a typical Residential customer, the per Mcf increase is applied to a substantially higher level of consumption. This translates into a far higher total increase for Rate IT customers under Mr. Mierzwa's proposal, which is 31.6%, as set forth on page 17 of my Rebuttal Testimony. The fact is that Mr. Mierzwa's recommended increase to Rate IT customers fails to incorporate the principle of gradualism. Moreover, the OCA's proposed increase is merely the minimum increase Rate IT customers would be subjected to because Mr. Mierzwa also embraces a one-year phase-in of PGW's alternate rate proposal. This expedited phase-in will increase IT rates substantially above those shown in Mr. Mierzwa's Table 2-R. Contrary to Mr. Mierzwa's Rebuttal Testimony, his proposals for Rate IT customers utterly fail to incorporate gradualism.

Q. On page 11, lines 5 through 11 of his Rebuttal Testimony, Mr. Mierzwa took issue with your testimony regarding the alternate fuel requirement in Rate IT. Please respond to Mr. Mierzwa's testimony on this point.

A. Mr. Mierzwa claims that not all Rate IT customers are interruptible based upon alternative fuel capability; however, according to PGW's response to PICGUG-VI-1, PGW has 422 Rate IT customers. Of that number, only 12 fall into the category of demonstrating the ability to manage their businesses without the use of gas during periods of curtailment. The other 410 Rate IT customers have alternative fuel capability. Thus, only a very small minority (*i.e.*, less than 3%) of Rate IT customers demonstrated the ability to operate without alternative fuel capability. The vast majority of Rate IT customers were required to have alternate fuel capability.

Q. On page 2 of his Rebuttal Testimony, Mr. Mierzwa testified that the OCA requested PGW rerun his recommended CCOSS to allocate 50% of distribution mains investment and costs based on throughput. Mr. Mierzwa's Table 3 Revised and Revised Schedule JDM-1 present the results of this revised CCOSS. Please present your conclusions with respect to this revised CCOSS.

A. Mr. Mierzwa's revised CCOSS contains a substantial error with respect to the classification and allocation of distribution mains. Therefore, his revised CCOSS cannot be used for purposes of cost and revenue allocation in this proceeding.

Mr. Knecht discussed the problem with Mr. Mierzwa's CCOSS on page 10 of his Rebuttal Testimony. Mr. Knecht pointed out this revised CCOSS incorrectly includes a 36.3% allocation of commodity-related mains to the GTS/IT class. This is incorrect because this allocation includes volumes associated with two large GTS customers who are served from directly assigned mains. I reviewed this revised CCOSS, which was provided by PGW in response to OCA-VII-7 on June 5, 2017, and my review confirms the error described by Mr. Knecht. The error causes a substantial misallocation of costs to the GTS/IT class and a significant overstatement of cost responsibility for the combined GTS/IT class in Mr. Mierzwa's revised CCOSS. The GTS volumes should not have been included in the allocation of commodity-related mains to the GTS/IT class.

Turning back to Mr. Mierzwa's Table 3 Revised on page 2 of his Rebuttal Testimony, the GTS/IT class rate of return is substantially understated due to the misallocation of mains costs. I agree with Mr. Knecht that this revised Peak and Average CCOSS cannot be used for revenue allocation in this proceeding.

Finally, my comments and critique of the peak and average CCOSS that are included in my Direct and Rebuttal Testimonies still fully apply to Mr. Mierzwa's revised CCOSS.

Q. Did the OCA request PGW to rerun the P&A CCOSS?

A. Yes. The Company submitted a revised P&A CCOSS on June 19, 2017, that apparently corrected the CCOSS relied upon by Mr. Mierzwa. I have not fully evaluated this CCOSS, but it appears to have excluded the volumes from the GTS customers that were included in the P&A CCOSS that Mr. Mierzwa relied on in his Rebuttal Testimony.

Despite the revision in this second revised P&A CCOSS, I recommend that the Commission reject this study. This study allocates a full share of distribution mains costs to Rate IT customers, which includes a demand portion based on design day demand and an average demand allocation based on total volumes for Rate IT. It therefore fails to recognize the interruptible nature of Rate IT service and allocates distribution mains costs to Rate IT on the same basis as firm service customers.

Q. Mr. Knecht discusses the merits of the peak and average ("P&A") and customer/demand ("CD") CCOSS approaches in his Rebuttal Testimony. Does anything in his discussion change your view on the appropriateness of the CD CCOSS in this proceeding?

A. No. For the reasons stated in my Direct and Rebuttal Testimonies the CD CCOSS is the appropriate approach for allocating costs to customer classes, and Mr. Hanser supports this method as well.

Q. On page 8 lines 12 through 26 of his Rebuttal Testimony, Mr. Knecht recommends moving toward a direct assignment method for allocating costs to customer classes. Please comment on Mr. Knecht's suggestion.

A. One of the major drawbacks of such an approach is that it could lead to the balkanization of PGW's system and result in substantially different rates for customers across the system. This could also lead to confusion on the part of PGW's customers. However, there may be some merit to segregating smaller and larger distribution mains and assigning costs of smaller distribution mains to the customers who use those mains. For example, larger customers may never use smaller sized mains that serve Residential customers, yet they are allocated the cost of those mains in the CD and the P&A CCOSS, as well as Mr. Knecht's Average and Excess ("A&E") CCOSS.

Q. On page 13, lines 5 through 12 of his Rebuttal Testimony, Mr. Knecht testified that, if the Commission rejects his proposal that no universal service costs be allocated to non-residential customers, Rate IT should share in the allocation of these costs. Please address Mr. Knecht's testimony on this point.

A. I disagree with Mr. Knecht and recommend that Rate IT customers receive no allocation of universal service costs. Indeed, my recommendation that IT rates be based on the cost to serve would preclude an allocation of universal service costs to Rate IT, which is not responsible for those costs and receives no benefit from them.

Q. On page 5 of his Rebuttal Testimony, Mr. Apetoh recommended that the Commission reject your proposed allocation of main costs based on the number of customers. Please respond to Mr. Apetoh's testimony on this point.

A. Mr. Apetoh did not present any new evidence regarding the proper classification and allocation of distribution main costs in his Rebuttal Testimony that would change my support of classifying and allocating costs based on contribution to peak demand and the number of customers. I continue to recommend the use of the CD CCOSS method, subject to my concerns about using the design day allocator for Rate IT customers.

Q. On page 13, lines 2 through 15 of your Rebuttal Testimony, you explained that you were waiting to receive further discovery responses regarding whether GTS customers were taking service from the Company's integrated distribution system. Did you receive the additional responses from PGW?

A. Yes. In addition, both Mr. Hanser and Mr. Dybalski presented Rebuttal Testimony supporting the contention that two large GTS customers which were included in the combined GTS/IT class in Mr. Hanser's CCOSS do not take service from PGW's integrated distribution system. PICGUG's Request PICGUG-VII-1 requested that the Company provide all supporting studies, documentation, and other materials showing that the GTS customers only take service from the directly assigned distribution mains shown in Mr. Hanser's CCOSS. The Company's filed response on June 13 indicated that the response to this request was pending.

Q. Mr. Hanser responded to your Direct Testimony regarding the cost to serve GTS customers and the rate of return for the combined GTS/IT class beginning on page 10 of his Rebuttal Testimony. On page 12, lines 10 through 12 of his Rebuttal Testimony Mr. Hanser testified that your conclusion with respect to GTS customers being responsible for the low rate of return for the combined GTS/IT class is incorrect. Please respond to Mr. Hanser's testimony on this point.

A. After reviewing PGW's discovery responses and the Rebuttal Testimony from Mr. Hanser and Mr. Dybalski, it appears that the GTS customers are likely not fully responsible for the low rate of return from the combined GTS/IT class in Mr. Hanser's CCOSS.

Q. Does the Rebuttal Testimony filed by Mr. Hanser and Mr. Dybalski, as well as PGW's discovery responses, affect your recommendation with respect to revenue allocation for Rate IT customers?

A. In my view, there remains uncertainty with respect to the proper cost allocation for Rate IT customers. Although I agree with the general approach Mr. Hanser presented in his CD CCOSS, I remain concerned that the design day demand for Rate IT customers is too high given their interruptibility. The P&A CCOSS and the A&E CCOSS are inappropriate for the reasons I explained in my Rebuttal Testimony. Further, the revised P&A CCOSS presented by Mr. Mierzwa contains a substantial error that results in a gross overstatement of cost responsibility for the combined GTS/IT class.

Given this uncertainty, I continue to recommend a system average increase for Rate IT customers.

Q. If the Commission decides to adopt the P&A method, what is your recommendation?

A. If the Commission decides to adopt the P&A CCOSS, then the study provided by Mr. Apetoh is probably the closest to being correct, although it is still quite flawed. As I stated on page 10 of my Rebuttal Testimony, allowance must be made in the P&A CCOSS for the interruptibility of Rate IT customers. Rate IT should not be given a full share of main costs in the P&A CCOSS given their interruptibility. This would essentially put Rate IT customers on equal footing with firm service customers with respect to responsibility for distribution mains costs, which is not appropriate.

Q. If the Commission decides to increase revenues for Rate IT at a percentage that is greater than the system average, do you have a recommendation as to how such a percentage be applied by the Commission?

A. Yes. Mr. Apetoh's approach is the least objectionable of all the parties that have submitted revenue allocation recommendations in this proceeding.

However, Mr. Apetoh's recommendation requires some modification. In his Direct Testimony, his recommended 20.99% increase for the combined GTS/IT class is 1.48 times the system average increase of 14.2%. Unfortunately, since the increase can only be collected from Rate IT customers, Mr. Apetoh's revenue increase winds up being a 23.5% increase to Rate IT, which is 1.65 times the system average increase.

Assuming arguendo that my recommended revenue increase is not adopted, I recommend that the Commission limit any increase to Rate IT customers to 1.5 times the system average increase. This approach reasonably incorporates the principle of gradualism with respect to class rate increases that the Commission may order in this proceeding irrespective of the class of customers involved.

Q. Do you have any concluding observations for the Commission to consider?

A. Yes. PGW, the OSBA, and the OCA have recommended extreme increases for Rate IT customers in this proceeding. It is important to keep in mind that the increases recommended by PGW and the OCA merely set the floor rate for IT, which would likely be increased to the maximum extent possible under the so-called negotiated alternative rate structure. Increases to PGW's customers that could reach over 250% - 300% are totally unreasonable, and the Commission should reject any proposal that would subject customers under its jurisdiction to such treatment. Imposing this type of increase on residential and commercial customers would be just as objectionable. There is no reasonable basis or standard by which the potential increases recommended by PGW and the OCA can be justified. Likewise, the 50% increase recommended by the OSBA would also violate the principle of gradualism. If the Commission decides to increase rates to IT customers more than the system average increase, it should apply the same standard of gradualism that it would apply to residential and commercial customers.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

PICGUG Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2017-2586783
PHILADELPHIA GAS WORKS	:	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

PHILADELPHIA INDUSTRIAL AND COMMERCIAL GAS USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.

MAY 16, 2017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2017-2586783
PHILADELPHIA GAS WORKS	:	

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Philadelphia Industrial and Commercial Gas Users Group ("PICGUG").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to provide recommendations regarding cost allocation, revenue allocation, and rate design to the Pennsylvania Public Utility Commission ("PUC" or "Commission"). In so doing I will respond to the Direct Testimonies of Mr. Douglas Moser and Mr. Philip Hanser, witnesses for Philadelphia Gas Works ("PGW" or "Company").

Q. Please summarize your conclusions and recommendations to the Commission.

A. My conclusions with respect to PGW's cost and revenue allocation and rate design proposals are as follows:

1. PGW's selection of a Customer/Demand approach to the classification and allocation of distribution mains in the class cost of service study ("CCOSS") presented by Mr. Hanser is an appropriate beginning for allocating cost responsibility to customer classes.

2. However, Mr. Hanser's CCOSS inappropriately combines Interruptible Transportation ("IT") customers and General Transportation Service ("GTS") customers into one class. These two classes are fundamentally different and should not be combined for purposes of a class cost of service study. The

difference lies in the fact that GTS customers receive firm service from PGW, while IT customers receive interruptible service.

3. Moreover, the rate of return for the combined GTS/IT customer class is significantly understated in PGW's CCOSS. This understatement is because PGW is providing heavily discounted rates from the Company's current tariffed rates to GTS customers resulting in a reduction in revenues for PGW. Consequently, PGW's CCOSS fails to provide an accurate portrayal of the rate of return for IT customers taking service at current cost-based tariff rates.

4. Combining the GTS and IT classes in Mr. Hanser's CCOSS results in highly inaccurate results for both classes of customers. Therefore, PGW's CCOSS cannot be relied upon for purposes of determining class revenue allocations generally and cost based rates specifically for the IT class in this proceeding.

5. Mr. Hanser proposed a grossly excessive 59% rate increase for Rate IT customers. Even worse, this increase would provide the low end of the range of rates that PGW could charge IT customers if PGW's request to implement a negotiated rate process is approved. The Company's filed CCOSS does not support a 59% rate increase to IT customers. Furthermore, such a proposal would result in rate shock to the IT class.

6. PGW witness Moser proposed a radical and unreasonable change to the IT class. Mr. Moser recommended that interruptible customers be subjected to pricing based on the cost of alternative fuels and rates for firm service customers. Under Mr. Moser's proposed change, IT rates would no longer be based on the allocated cost to serve IT customers. However, IT customers would still be subject to interruption and would be required to maintain alternative fuel capabilities. This arbitrary and adverse proposal should be rejected out of hand by the Commission.

My recommendations to the Commission are as follows:

1. Rates for the IT class should continue to be based on the allocated cost to serve those customers, not on value of service pricing.

2. PGW should be required to file a CCOSS in its next case that separates GTS and IT customers, as these customer classes have different levels of service.

3. Mr. Hanser's proposed 59% increase to IT customers should be rejected.

4. For purposes of this case, Rate IT should receive no more than a system average percentage increase in this proceeding. The majority of any rate increase to IT customers should be collected through the fixed charges, or, at a minimum, both the customer charges and volumetric charges should be increased at the system percentage increase.

5. Mr. Moser's proposed restructuring of IT rates should be rejected.

6. Rate IT should be continued as currently structured in PGW's tariff.

7. PGW, as part of its next base rate proceeding, should be required to propose firm transportation service for large commercial and industrial customers that is cost-based and in alignment with other natural gas distribution companies in Pennsylvania.

II. COST AND REVENUE ALLOCATION

Q. Did you review PGW's CCOSSs?

A. Yes. Mr. Hanser sponsored the Company's CCOSS in his Direct Testimony.

Q. Please provide a general description of the process of allocating cost responsibility to customer classes using a cost of service study.

A. A class cost of service study allocates and assigns the total cost of providing utility service to the classes of customers receiving that service. In certain instances, the subject utility can identify and directly assign costs to customers. For the vast majority of costs, however, such direct assignments are not possible and a cost of service study is required so that the remaining costs may be allocated to customers.

The development of a class cost of service study consists of three steps: functionalization, classification, and allocation. Step 1, functionalization, involves separating the utility's investment and expenses into major functional categories. For natural gas utilities such as PGW, these categories may include production, storage, transmission, and distribution functions. The FERC Uniform System of Accounts provides the method by which costs are identified and placed into these various functional categories.

Step 2 is classification. Once functionalization is complete, the utility's costs are classified into demand, commodity, and customer components. Demand-related costs are fixed and do vary with the monthly and yearly gas commodity consumption of the utility's customers. These costs are driven by demands placed on the system during the winter peak period and include such items as gas main investment and expenses. Commodity-related expenses vary with the amount of gas consumed by customers and include the cost of gas and certain operation and maintenance expenses. Customer-related costs are associated with the number of customers and include items such as a portion of main investment, meters, and services.

Step 3 is allocation. After costs are classified, they are allocated to customer classes based on each class' contribution to the respective cost classifications. Generally speaking, demand costs are allocated based on each class' contribution to the total winter peak. Commodity costs are allocated based on each class' share of total yearly consumption, or throughput. Customer costs are allocated based on the number of customers.

Q. Do you agree with Mr. Hanser's proposed classification and allocation of distribution mains?

A. I agree with the general approach of classifying and allocating mains based on contribution to peak demand and the number of customers.

Q. Please explain why distribution mains should be classified as both demand and customer related for purposes of the Company's CCOSS.

A. The two main functions of distribution mains are to deliver gas during the system winter peak and to connect customers to the system. A properly designed zero-intercept study or minimum size system study recognizes these two functions by classifying main costs into demand-related and customer-related costs, which can then be assigned to customer classes based on their respective contributions to system peak and on the number of customers in each class.

Peak winter demand is one of the primary drivers of PGW's investment in gas distribution mains. The Company must have sufficient capacity available on its system to satisfy the peak winter heating demand, which is caused mainly by residential customers. If the peak winter demand increases, the Company may need to invest in additional mains to serve the load. During the non-winter months, substantial excess capacity exists on the system. Use of the Company's distribution system during these months does not cause additional fixed costs to be incurred by the Company. In fact, high load factor customers provide valuable margins to the Company during off-peak months when the demands of residential heating customers are very low. In a similar manner to peak winter demand, if the number of customers increases, the Company may need to expand its distribution system investment. Thus, the number of customers connected to the distribution system is another important causative factor in distribution main investment. In my view, this is just obvious common sense in terms of the two factors that drive a gas distribution company's costs of distribution mains.

Q. Is it appropriate to classify and allocate a portion of the costs of mains on the basis of total throughput?

A. No. Peak winter demands and the number of customers drive investment in distribution mains, not gas consumption throughout the year. If the peak winter demand increases, the Company may need to invest in additional mains to serve the load. Likewise, if the number of customers increases, the Company may need to expand its distribution system investment. In my view, this is just obvious common sense in terms of the two factors that drive a gas distribution company's main costs.

Throughput, which varies substantially during the year, is not what causes PGW's investment in the *fixed costs* of distribution mains. During the non-winter months, substantial excess capacity exists on the system. In fact, high load factor customers provide valuable margins to the Company during off-peak months when the demands of residential heating customers are very low.

Q. Have you prepared a table illustrating the effect of winter heating load on PGW's system?

A. Yes. Table 1 below shows monthly sendout for the Residential Heating, Commercial Heating, and GTS/IT classes for the twelve months ending August 2018. I calculated the average monthly consumption for the heating and non-heating seasons from the data and included them in Table 1.

TABLE 1

Monthly Mcf Sendout by Rate Class

	Res - Heat	Comm - Heat	GTS/IT
09/2017	712,817	284,584	1,946,773
10/2017	1,636,094	490,438	2,183,886
11/2017	3,585,024	908,653	2,432,056
12/2017	5,482,495	1,320,826	2,763,749
01/2018	7,271,558	1,704,090	3,006,953
02/2018	6,375,686	1,498,209	2,711,090
03/2018	4,698,808	1,152,218	2,629,761
04/2018	2,302,476	631,361	2,222,630
05/2018	1,056,510	366,539	2,057,779
06/2018	680,364	281,306	1,937,765
07/2018	699,639	291,385	1,995,852
08/2018	696,086	292,121	1,995,852
Totals	35,197,557	9,221,729	27,884,147
Monthly Avg., Heating Season	4,478,877	1,100,828	2,564,303
Monthly Avg., Non-Heating Season	697,227	287,349	1,969,061

Heating season defined as October - May
Source: Exhibit PQH-8C

Note the dramatic increase in the average monthly heating season Mcf for the Residential and Commercial classes. The GTS/IT classes have a far more even usage pattern throughout the year and have a much smaller difference between heating and non-heating season average monthly consumption compared to the Residential and Commercial Heating classes of customers.

Q. Please summarize the results of the CCOSS presented by Mr. Hanser.

A. Table 2 summarizes the customer class rates of return at current rates from the CCOSS presented by Mr. Hanser.

TABLE 2
Class Rates of Return and Relative Rates of Return

	Current Return on Rate Base	Relative ROR	Proposed Return On Rate Base	Relative ROR
Residential	3.7%	0.78	9.6%	0.91
Commercial	12.3%	2.62	15.9%	1.50
Industrial	12.9%	2.75	8.7%	0.82
PHA GS	3.9%	0.82	13.7%	1.29
Municipal/PHA	4.1%	0.87	6.6%	0.62
NGVS	13.4%	2.84	13.4%	1.26
Interruptible	-16.4%	-3.50	-16.4%	-1.55
GTS/IT	1.7%	0.37	20.3%	1.92
Total	4.7%		10.6%	

The relative rate of return ("RROR") ratios provide a measure of each class' rate of return compared to PGW's system average rate of return. A relative rate of return of less than 1.0 indicates that a rate class is providing less than the system average return. A relative rate of return greater than 1.0 indicates that a customer class is providing a rate of return greater than the system average. For example, the current RROR for the Residential class is 0.78, meaning its current return is lower than the system average return on 4.7%. Alternatively, Commercial customers' RROR is 2.62, showing that this class is significantly above the system average rate of return.

Q. Mr. Baudino, does the current rate of return percentage and relative rate of return for the GTS/IT class accurately portray the rate of return for IT customers?

A. No, it does not. The 1.7% combined class rate of return is due to the inclusion of GTS customers, which have steeply discounted rates that have been held constant per contracts with PGW since at least 2003, as that is when PGW closed Rate GTS to other customers. These contracts are steeply discounted compared to both firm service and interruptible transportation service rates for PGW. These discounted GTS contracts are solely responsible for the low rate of return and RROR that show up in Mr. Hanser's CCOSS for the GTS/IT class.

Q. How much of the GTS/IT class revenues come from GTS customers?

A. From the Company's original filing, GTS sales were 13,176,839 Mcf, which represents 48% of total GTS/IT sales. In comparison, GTS customers generated $1,249,147 in revenues, representing 10.3% of total revenues for the combined GTS/IT class.

Q. What is the average revenue per Mcf from GTS customers compared to IT customers?

A. Table 3 below shows the average revenue per Mcf from GTS and IT customers separately. The average GTS revenue per Mcf is only $0.095 (9 ½ cents) compared to the average IT revenue per Mcf of $0.769 (76.9 cents). The difference between these two sets of customers is $0.674 per Mcf.

TABLE 3 GTS and IT Avg. Rate Comparison		
Current GTS Revenues	$	1,249,147
Current IT Revenues	$	10,928,669
Total GTS/IT Sales		27,393,512
Less: IT Sales		14,216,673
GTS Sales		13,176,839
IT Average $/mcf	$	0.769
GTS Average $/mcf	***$***	***0.095***
Difference	***$***	***0.674***

Q. If GTS customers provided revenues closer to those generated by IT customers, would the CCOSS results change?

A. Yes. If GTS customers provided the same average revenue per Mcf as IT customers, they would generate an additional $8.88 million per year in revenues. Now, Mr. Hanser's Exhibit PQH-1, page 1 of 1, line 7, shows that the GTS/IT class requires an additional $2.598 million to reach its full cost of service revenue level. Thus, the additional $8.88 million in revenues from GTS customers would completely turn the CCOSS study results around and show a higher than average return for the combined GTS/IT classes.

There is another way to view this situation as well. To generate the additional $2.598 million in revenues to bring the GTS/IT class to its cost of service, the average GTS rate would need to increase by $0.20 per Mcf, bringing the total average rate to $0.295. This rate is still far below the average IT revenue per Mcf.

Q. What do you conclude from the foregoing analysis and discussion?

A. The conclusion is obvious. It is the deeply discounted GTS contract customers that are responsible for the 1.7% rate of return from the combined GTS/IT class, not the IT customers in that combined class.

Q. Do you have further explanation or qualification of the results shown in Table 3?

A. Yes. The CCOSS results are also problematic because IT and GTS customers have fundamentally different service characteristics. GTS customers are firm service customers and should be allocated costs commensurate with firm transportation service. IT customers are interruptible and should be allocated costs that reflect their much lower reliability of service. In other words, IT customers can be interrupted during peak periods while GTS customers cannot be. Two such different classes should not be combined for purposes of a CCOSS study. This is a significant flaw in the Mr. Hanser's CCOSS.

Q. Could PGW have produced a CCOSS that separated GTS and IT customers?

A. According to PGW, no. PGW's response to OCA-VII-1 claimed that data limitations precluded separate CCOSS analyses for GTS and IT customers. *See* Exhibit___(RAB-3). Importantly, however, PGW had only three customer accounts on Rate GTS, and, in April 2017, one of those three customer accounts left PGW's system altogether.[1] *See* Exhibit___(RAB-3). The small number of customers in the

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[1] Although PGW included the volumes of all three customer accounts in its Fully Projected Future Test Year, the volumes of the customer account that left the system in April 2017 represented approximately 8.5% of the GTS volumes at issue.

GTS class suggests that separating the classes should not be difficult for PGW to accomplish. Moreover, if only two customer accounts remain, PGW should certainly be able to overcome any data limitations for purposes of separating GTS and IT customers as part of any future CCOSS. Regardless, because of PGW's claimed data limitations, we cannot accurately ascertain the specific rate of return for IT customers for purposes of this proceeding.

Q. Should PGW be required to address the limitations of the data supporting its proposed allocation factors?

A. Yes. PGW's explanation as to why it combined GTS and IT customers is wholly insufficient. The Commission should require PGW to separate GTS and IT customer demands, volumes, and customer counts in its next rate case. I will address this more fully in my CCOSS recommendation later in my testimony.

Q. Turning now to revenue allocation, what was Mr. Hanser's proposed revenue increase to IT customers?

A. *Mr. Hanser proposed a staggering 59% revenue increase to Rate IT customers, as compared to PGW's overall requested increase of 14.2%. Thus, Mr. Hanser's proposed increase to IT customers is 415% higher than the overall requested increase.*

Q. Does Mr. Hanser's testimony and exhibits reflect a 59% increase to Rate IT customers?

A. No. On page 1 of Mr. Hanser's Exhibit PQH-1, he reflects a rate increase of 44.9% to the GTS/IT class; however, that increase is understated because, arithmetically, the CCOSS presentation assumes that any rate increase will be borne by the GTS and IT customers. Because Rate GTS is a negotiated rate, in actuality, all of the rate increase would be allocated to Rate IT, resulting in the aforementioned 59% rate increase.

Q. What is your recommendation with respect to Mr. Hanser's increase to Rate IT?

A. I recommend that the Commission reject Mr. Hanser's unwarranted, baseless, and economically harmful proposed increase to IT customers. My analysis shows that it is the GTS customers that are causing the shortfall in total GTS/IT combined class revenues, not IT customers. Therefore, there is no good reason for IT customers to suffer a 59% revenue increase. Moreover, as I noted previously, the GTS/IT combined classes have nothing in common, so requiring IT customers to shoulder the entirety of any differential between actual and negotiated revenues for GTS customers is unreasonable. Either all of PGW's customers should be responsible for the subsidization of GTS customers or PGW should take responsibility for this differential, as PGW entered into these GTS negotiated rates at least fourteen years ago with no evidence in this proceeding showing that the rates and terms of these heavily discounted contracts are still appropriate.

Q. On page 22, lines 17 through 19 of Mr. Hanser's Direct Testimony, he testified that he allocated a portion of the revenue increase to the IT Rate Class "to reflect the fact that the IT customer demand drives many of the costs associated with building and operating the system." Do you agree with this statement?

A. No. Mr. Hanser's 59% rate increase to IT customers in no way reflects cost responsibility for this customer class. As I demonstrated previously, it is the GTS customers who are solely responsible for the low 1.7% return for the combined GTS/IT customer class.

Q. Does Mr. Hanser's proposed 59% increase to Rate IT customers constitute rate shock?

A. It most certainly does. It also flies in the face of the gradualism principle, which generally provides that rates and revenue should be increased gradually over time to avoid excessively large rate increases to customers.

It is important to note that in PGW's last rate case, in 2009, Mr. Dybalski considered gradualism as a principle in allocating the Company's revenue. On page 5 of Mr. Dybalski's Direct Testimony in that proceeding he stated the following:

> 1) Observe the principles of gradualism and avoid rate shock by allocating the rate increase in such a way that carefully moves all classes closer to the system rate of return when compared to PGW's 2006 base rate case filing (Docket No. R-00061931).

Direct Testimony of Kenneth S. Dybalski, PGW Statement No. 5, *Pa. PUC v. Philadelphia Gas Works*; Docket No. R-2009-2139884 (2009), p. 5. Mr. Hanser made no such careful move with his 59% rate increase to Rate IT customers in this case. His proposal is wildly inconsistent with PGW's approach in Docket No. R-2009-2139884.

Q. Did you attempt to ascertain the basis for Mr. Hanser's contention regarding cost responsibility for Rate IT customers?

A. Yes. PICGUG asked the Company to explain in detail how Mr. Hanser's proposed revenue increase reflected the "fact" that the IT customer demand drives many of the costs associated with building and operating the system. In its response to PICGUG-II-9, included in Exhibit ___(RAB-3), the Company responded as follows:

> While Rate IT customers do not contribute to design-day demand, their needs are still being met by the distribution system. As discussed by Company witness Moser in PGW St. No. 7, PGW has been able to avoid interrupting Rate IT customers during the winter

> and permitted them to continue to stay on the system on peak days. Mr. Moser also explains that the gas distribution system is maintained and modernized for all customers, including those in the Rate IT class. Because not all capacity costs imposed by these customers on the system can be avoided, some portion of capacity costs should be allocated to Rate IT customers.

See Exhibit___(RAB-3). This response fails to support Mr. Hanser's proposed 59% increase to IT customers. IT customers are indeed being allocated their fair share of capacity costs and other distribution expenses in the CCOSS presented by Mr. Hanser. What PGW and Mr. Hanser failed to explain is how a 59% revenue increase that results in a 20.9% rate of return reflects IT cost responsibility. The fact is that it does not reflect IT cost responsibility in any way.

The Company's response to PICGUG's data request also misses the main point of IT's service characteristics. IT customers must invest in alternate fuel capability and be ready to interrupt their gas consumption when needed. Just because system conditions precluded the need for interruptions over the last several years does not mean that IT customers will never be interrupted and that, therefore, they are receiving firm service. PGW's tariff clearly states that IT service is interruptible and, therefore, is not firm. PGW's data request response also confirmed the fact that IT customers do not contribute to design day demands. This is not the case for firm service customers who do contribute to design day demands and are allocated costs on that basis.

In conclusion, Mr. Hanser and PGW have no basis whatsoever for the assertion that IT customers are not contributing their fair share of costs and that an economically harmful 59% rate increase is justified.

Q. Do IT customers incur costs for their service that firm customers do not incur?

A. Yes. IT customers must install and maintain alternate fuel capability in order to receive service under the IT rate schedule. This is a significant additional cost that IT customers incur that firm service customers do not incur.

Q. If IT customers chose to receive firm service, would PGW incur additional costs to serve them?

A. Yes. In PGW's response to OSBA-I-31, the Company was asked to estimate its investment requirement to provide firm service to IT customers. The Company responded as follows.

> D. If Rate IT customers converted to firm service, there would be an increase need of system supply. This increase in volume would be met with a combination pipeline firm transportation, expansion of city gate capacity, expansion of PGW distribution system infrastructure and/or additional LNG capability. The exact mix would need additional studies to finalize.

See Exhibit___(RAB-3). This response confirms that IT customers do not impose the same costs on PGW's system as firm customers. In essence, IT customers provide system savings due to their lower reliability of service. It is inappropriate to allocate costs and revenue increases to Rate IT as if it were receiving firm service.

Q. Based on the foregoing discussion and analysis of PGW's flawed CCOSS, what is your recommended approach to revenue allocation?

A. I recommend that the Commission increase IT revenues by the system average increase. Please refer to Exhibit ____(RAB-2) for my recommended class revenue allocation.

For purposes of this case, I increased IT revenues by the Company's proposed 14.2% increase, or $1.5 million. Mr. Hanser's proposed increase was $5.5 million for IT. I allocated the difference, $4.0 million, to the Residential class since that class was returning revenues below its allocated cost to serve. This resulted in an increase to Residential customers of 16.3%, which is 1.15 times the system average increase. I accepted Mr. Hanser's revenue allocation to the other rate classes.

Q. Please explain why the system average increase is appropriate for Rate IT customers.

A. The main challenge with PGW's CCOSS is that GTS and IT customers are lumped into one class for purposes of cost allocation. We cannot know how much, if any, of the rate increase should be assigned to the IT rate class. Nevertheless, my analysis of GTS revenues suggests that if those customers were paying rates commensurate with costs, the combined GTS/IT rate class would be returning revenues far greater than the cost to serve them. Therefore, it would be reasonable to give IT customers no increase in this proceeding.

I recognize, however, that the CCOSS does not specifically separate IT customers. Because the GTS/IT class is so far below the cost to serve, and in light of the flawed CCOSS allocations, I believe a fair and reasonable compromise in this proceeding would be for Rate IT to receive an increase no greater than the system average increase with the caveat that PGW be required in its next base rate proceeding to provide a CCOSS that specifically separates the GTS/IT class so that a comprehensive determination can be made with respect to the Rate IT customers' cost to serve.

Q. What is your recommended rate design for IT customers?

A. Since most of the costs of PGW's system are fixed, more of the IT revenues should be collected through the fixed charges. Unfortunately, PGW recommended holding customer charges constant, with the entirety of the 59% rate increase flowing through volumetric rates. Because this is unreasonable, I recommend that the majority of any rate increase to IT customers be collected through the fixed charge or, at a minimum, both the customer charges and volumetric charges be increased at the system percentage increase.

Q. Should the current language in Rate IT be continued and approved by the Commission?

A. Yes. The language changes proposed by the Company to Rate IT should be rejected. The only changes in the Rate IT tariff language should be the new rates approved by the Commission.

Q. What is your recommendation regarding cost allocation for GTS and IT customers?

A. I recommend that the Commission order PGW to separate GTS and IT customers into separate rate classes in the CCOSS filed in the Company's next rate proceeding. As I testified earlier, PGW's alleged data limitations are no excuse for combining these two very different classes of customers. The Commission should order PGW to separately identify all demand, volumetric, and customer allocation factors for GTS and IT customers by its next rate proceeding.

III. INTERRUPTIBLE TRANSPORTATION PROPOSAL

Q. Briefly describe Mr. Moser's proposal for the IT rate class.

A. Mr. Moser set forth his proposal for Rate IT beginning on page 27 of his Direct Testimony. In essence, Mr. Moser's proposal consists of the following main points:

- IT rates would no longer be based solely on the cost to serve. Mr. Moser proposed to move to a negotiated rate approach that moves significantly away from cost of service principles.
- PGW would establish price ranges for IT rates. The lower end of the range would be the cost based IT rate established in this and future rate proceedings. The upper end of the range would be based on a so-called "equivalent transportation rate," which is actually a firm service rate.
- The distribution charge would be negotiated by the IT customer and the Company within the established range. The negotiated rate would reflect the cost of service as well as "competitive considerations."
- IT rates would reflect cost of service and "value of service pricing principles."

Q. What is your recommendation with respect to Mr. Moser's IT rate proposal?

A. The Commission should reject Mr. Moser's IT rate proposal.

Q. Why should the Commission reject Mr. Moser's IT proposal?

A. Mr. Moser's Rate IT proposal is a misguided attempt to fix a problem with Rate IT that quite simply does not exist. I will summarize the major flaws as follows:

First, PGW presented no evidence that IT customers are not paying their fair share of system costs. In fact, it is the GTS customers that are being heavily subsidized by PGW's customers, and, as noted in my testimony above, PGW is specifically seeking to have Rate IT customers subsidize the GTS customers through PGW's combination of the GTS/IT classes for the CCOSS.

Second, Mr. Moser's proposed value of service pricing would allow the Company to charge excessive and economically damaging rates to IT customers. These excessive rates would result in IT customers paying PGW excessive returns. Regulation should prevent the kind of pricing abuses that PGW is attempting to inflict on IT customers with this so-called value of service pricing approach.

Third, Mr. Moser attempted to characterize IT customers as being more risky than other classes of customers. I disagree with this assertion. In fact, IT customers are likely less risky than temperature sensitive customers, such as Residential customers.

Fourth, simply because UGI, Inc. ("UGI"), has long standing negotiated interruptible tariff that fit its system, this is not sufficient grounds for the kind of unreasonable IT rate proposal for which Mr. Moser seeks approval, especially since UGI's services available to large commercial and industrial customers seeking firm transportation service are significantly different than those provided by PGW.

Finally, if PGW seeks to offer firm transportation service to large commercial and industrial customers, PGW should be required to do so on a basis that it is reflective of the cost to serve those types of customers.

Q. Regarding your first point, please explain why PGW failed to show that IT customers are not paying their fair share of system costs.

A. I discussed this point at length in Section II of my Direct Testimony. Mr. Hanser's flawed CCOSS combined GTS and IT customers into one rate class. Given the heavily discounted rates for GTS customers, the rate of return for the GTS/IT class is unrealistically low and fails to show the correct rate of return for IT customers. The low rate of return for GTS/IT is completely due to GTS customers, not IT customers. PGW's CCOSS presentation hides the huge GTS rate subsidy in the combined GTS/IT class. GTS customers are being subsidized by all PGW customers. However, neither Mr. Hanser nor Mr. Moser made any mention of this important fact. This subsidy is likely several million dollars per year. By imposing a 59% rate increase on IT customers, Mr. Hanser, Mr. Moser, and PGW are essentially trying to collect the entire GTS rate subsidy, and a lot more, from IT customers. This is totally unreasonable, and the Commission should reject PGW's IT rate proposal on this basis alone.

Q. Regarding your second point, please explain why the Commission should continue a cost of service approach to IT pricing rather than a value of service pricing.

A. Absent a compelling reason to the contrary, the Commission should continue its approved cost of service based pricing for all customers, including IT customers.

Cost of service is the bedrock of utility pricing principles. In fact, the Pennsylvania Commonwealth Court has indicated that cost of service is the polestar in determining a utility's rates. *See Lloyd v. Pa. PUC*, 904 A.2d 1010 (Pa. Commw. Ct. 2006). A utility's customer classes should provide revenues that reflect the costs to serve them. In this manner, all customers are treated fairly and equally. Deviations from cost of service introduce economic inefficiencies into the utility's pricing structure. This happens because improper pricing signals are conveyed to customers. For example, if PGW's prices for its distribution service are too high, then customers will cut back on their use of gas and search out other substitutes for heating. The opposite would be true if PGW's prices are too low. This would cause uneconomic consumption of natural gas above the level that would be consumed if prices were set equal to cost.

Moreover, the Commission has previously indicated that PGW's Rate IT should be cost-based. In PGW's 2007 distribution rate case, the Commission specifically directed PGW to establish cost-based transportation rates, noting that PGW had failed to show that the margin-based IT transportation rates were cost-based or just and reasonable. *See Pa. PUC v. PGW*, Opinion and Order; Docket No. R-00061931 (Sept. 28, 2007), p. 92.

Q. Would PGW's IT proposal allow the Company to earn excessive profits from IT customers?

A. Yes, absolutely. Mr. Moser's IT rate proposal is completely untethered from cost of service pricing principles. The lower bound of IT rates would be set at an excessive level that is based on Mr. Hanser's 59% rate increase to IT customers. <u>This would cause an excessive rate of return (20.9%) from IT customers as a starting point.</u> From there, the Company could negotiate the IT rate all the way up to the firm service rate. At the same time, IT customers' service would still be subject to interruption. Clearly, PGW would be earning supernormal profits from IT customers. The Commission should protect not just IT customers but all customers from this kind of monopolistic pricing abuse.

Q. Does the fact that PGW has not interrupted IT customers in the last few years suggest that IT customers are receiving firm service?

A. No. From a cost to serve standpoint, the Company clearly stated in its response to PICGUG-II-9 that Rate IT customers do not contribute to design-day demand. Therefore, they are not responsible for design day costs like firm service customers. Rate IT is allocated its share of mains costs based on the Company's mains allocator, which is based 50% on demand and 50% on the number of customers. Rate IT customers are thus paying for a portion of the Company's capacity costs.

Further, IT customers must invest in alternative fuel capability whether PGW interrupts them or not. In other words, IT customers must stand ready to be interrupted and have invested in the capability to meet such interruptions. Firm customers have no such alternative fuel investment or capability because none is required for their level of service.

Q. Regarding your third point, did Mr. Moser present any evidence that PGW may lose customers to alternative fuels?

A. No, he did not.

Q Are IT customers more risky than firm service customers?

A. I do not believe they are necessarily more risky than firm service customers. IT/GTS customers have lower variability of consumption throughout the year than do Residential and Commercial customers, who rely on gas for heating. Thus, weather will cause heating customers' consumption to vary substantially in either warmer or colder weather. Less weather sensitive customers in the GTS and IT classes have much lower variation in their monthly consumption as I showed in Table 1. Other things being equal, the consumption patterns of GTS and IT customers over a year suggests lower, not higher, risk than weather sensitive Residential and Commercial customers.

It is true that IT customers have alternatives to natural gas consumption, but the prices of those alternatives are quite a bit higher than natural gas as Mr. Moser showed on page 29 of his Direct Testimony. Given the price differences shown by Mr. Moser, it appears unlikely that Rate IT customers would switch from natural gas to the other alternatives he presented. Thus, there is very little risk from IT customer fuel switching at this point in time.

Q. Do the prices of alternative fuels shown by Mr. Moser on page 29 of his Direct Testimony support a change from cost of service pricing to value of service pricing?

A. Absolutely not. The only relevant consideration is whether IT rates are cost based. The price of alternative fuels is completely irrelevant as to proper pricing for IT customers.

In order to illustrate the fallacy of PGW's IT rate proposal, I provide the following example. Residential customers could choose to heat their homes with either natural gas or electricity. Let us assume that it costs an average Residential customer $150 per month to heat his or her home with natural gas. Assume further that it would cost $250 per month to heat that same customer's home with electricity. PGW's value of pricing approach would suggest that it would be perfectly fine to negotiate with that Residential customer and charge anywhere between $150 and $250 per month based on the alternative cost of heating with electricity. Once PGW's pricing is untethered from cost of service principles, it could charge our Residential customer $210 per month based on the rationale that it is still less than the electric heating alternative.

Obviously, regulation would not allow a utility company to price its services to Residential customers in such a manner. Neither should the PPUC allow PGW to price its service to IT customers using value of service pricing.

Q. Regarding your fourth point, why should the Commission disregard the UGI interruptible tariff in this case?

A. PGW's comparison to UGI's interruptible transportation tariff is irrelevant. The PPUC has already established the principle that PGW's interruptible transportation rates should be based on the cost to serve those customers. PGW failed to provide any sound basis for changing that finding to one that supports a value of service pricing approach that has been used by UGI for a number of years.

In addition, UGI's value of service pricing is based, in part, on the fact that UGI's interruptible customers can switch to firm transportation service if they so choose. While PGW claims to have a firm service, PGW fails to recognize that its "firm service," does not reflect the cost to serve large commercial and industrial transportation customers on a firm basis. For example, UGI offers two types of firm transportation service to large commercial and industrial customers, with rates of \$1.5470/Mcf to \$1.0465/Mcf for throughput and a demand charge of \$5.45/Mcf of the customer's daily firm requirement ("DFR"). Conversely, if a Rate IT customer sought to switch to firm transportation service, the customer's only option would be PGW's Rate GS delivery service, which is priced at \$4.5332/Mcf. Moreover, for large commercial and industrial customers just a few miles away in PECO's service territory, PECO offers a firm transportation charge of between \$1.6823/Mcf and \$0.7736/Mcf.

Thus, PGW's use of its purported "firm" service rate as a ceiling for value based pricing completely ignores the fact that PGW does not offer an actual firm transportation rate for large commercial and industrial customers. In order for PGW to utilize firm service as the basis for a rate involving large commercial and industrial customers, PGW must first be required to offer a cost-based firm transportation rate to these customers. Until that happens, PGW's value based pricing cannot be compared to UGI's pricing.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-2017-2586783
	:	
PHILADELPHIA GAS WORKS	:	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

PHILADELPHIA INDUSTRIAL AND COMMERCIAL GAS USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.

MAY 16, 2017

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
Atmos Cities Steering Committee
Canadian Federation of Independent Businesses
CF&I Steel, L.P.
Cities of Midland, McAllen, and Colorado City
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service

Expert Testimony Appearances
of
Richard A. Baudino
As of May 2017

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of May 2017

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of May 2017

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of May 2017

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042-000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of May 2017

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
of
Richard A. Baudino
As of May 2017

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
08/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
08/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation
09/16	2016-00162	KY	Kentucky Office of the Attorney General	Columbia Gas of Ky.	Return on equity, cost of short-term debt
09/16	16-0550-W-P	WV	West Va. Energy Users Gp.	West Va. American Water Co.	Infrastructure Replacement Program Surcharge
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring fencing and other conditions for acquisition, service quality and reliability
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP and Sharyland Dist. and Transmission Services, LLC	Return on equity
02/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
03/17	10580	TX	Atmos Cities Steering Committee	Atmos Pipeline Texas	Return on equity, capital structure, weighted cost of capital
03/17	R-3867-2013	Quebec, Canada	Canadian Federation of Independent Businesses	Gaz Metro	Marginal Cost of Service Study

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Date	Case	Jurisdict.	Party	Utility	Subject
05/17	R-2017-2586783	PA	Philadelphia Industrial and Commercial Gas Users Gp.	Philadelphia Gas Works	Cost and revenue allocation, rate design, Interruptible tariffs

PICGUG Recommended Revenue Allocation (000s)

	Total	Residential	Commercial	Industrial	PHA GS	Muni/PHA	NGVS	Interruptible	GTS/IT
Proposed Increase (decrease)	70,000	63,000	5,000	(400)	400	500	-	-	1,500
Current Distribution Revenue	491,318	385,459	77,324	5,899	1,499	8,852	20	18	12,246
Percentage Increase	14.2%	16.3%	6.5%	-6.8%	26.7%	5.6%	0.0%	0.0%	12.2%
Income Before Interest and Surplus	125,899	99,056	22,154	813	557	1,311	4	(10)	2,014
Rate Base	1,188,371	986,470	138,958	9,387	4,073	19,814	29	62	29,579
Return on Rate Base Before Int. and Surplus	10.6%	10.0%	15.9%	8.7%	13.7%	6.6%	13.8%	-16.1%	6.8%
Relative Rate of Return		0.95	1.50	0.82	1.29	0.62	1.30	(1.52)	0.64

Exhibit ___(RAB-2)

**Response of Philadelphia Gas Works ("PGW")
to the Interrogatories of the Office of Consumer Advocate, Set VII in
Docket No. R-2017-2586783**

Request: OCA-VII-1 Reference Exhibit PQH-1, page 1:

a. Please provide a separate breakout for the GTS Firm, GTS Interruptible, and IT rate classes; and

b. Please explain why PGW is proposing to increase the relative rate of return of the GTS/IT class to 1.92.

Response:

a. The breakout requested would necessitate the development of allocation factors for each of these classes individually. I am unable to provide such a breakout because the data granularity is not sufficient to derive allocation factors for the GTS Firm, GTS Interruptible, and IT rate classes.

b. The revenue increase for the GTS/IT class grouping is driven entirely by an increase to the IT Rate Class. Based on Company specification, I allocate a portion of the revenue increase to the IT class to reflect the fact that IT customer requirements drive many of the costs associated with building and operating the system. This specification is appropriate because the IT contribution to peak demand is not appropriately captured with the allocators used in the current CCOSS, and thus the results – including the class rate of return – somewhat understate their cost responsibility. Even though the IT customers are not contributing to demand on the peak day, their needs are still being met by the distribution system. While their interruptiblity could result in avoidance of costs that are strictly related to peak capacity, it does not avoid all capacity costs imposed by these customers on the system, throughout the year.

Response Provided by: Philip Q Hanser, Principal of The Brattle Group

Dated: April 17, 2017

RESPONSE OF PHILADELPHIA GAS WORKS ("PGW") TO THE INTERROGATORIES OF PHILADELPHIA INDUSTRIAL AND COMMERCIAL GAS USERS GROUP ("PICGUG"), SET II
DOCKET NO. R-2017-2586783

Request: PICGUG-II-9: Please refer to page 22, lines 17 through 19 of Mr. Hanser's Direct Testimony.

a. Please explain in detail how the proposed revenue increase to the IT Rate Class reflects "the fact that the IT customer demand drives many of the costs associated with building and operating the system."

b. Since Rate IT customers are interruptible, explain why IT customer demand "drives many of the costs associated with building and operating the system" according to Mr. Hanser.

c. Do Rate IT customers drive the costs associated with building and operating the system more than or less than firm customers? Provide a detailed explanation, including analyses performed by Mr. Hanser and/or PWG demonstrating that Rate IT customer demand "drives many of the costs associated with building and operating the system."

d. Does Mr. Hanser agree that interruptible customers allow a gas distribution company to free capacity on its system for the use of firm customers, thereby saving the Company and firm customers additional system capacity costs? Explain why or why not.

Response:

a. While Rate IT customers do not contribute to design-day demands, their needs are still being met by the distribution system. As discussed by Company witness Moser in PGW St. No. 7, PGW has been able to avoid interrupting Rate IT customers during the winter and permitted them to continue to stay on the system on peak days. Mr. Moser also explains that the gas distribution system is maintained and modernized for all customers, including those in the Rate IT class. Because not all capacity costs imposed by these customers on the system can be avoided, some portion of capacity costs should be allocated to Rate IT customers.

b. Please see response to part (a) above.

c. See response to PICGUG II-13(a).

RESPONSE OF PHILADELPHIA GAS WORKS ("PGW") TO THE INTERROGATORIES OF PHILADELPHIA INDUSTRIAL AND COMMERCIAL GAS USERS GROUP ("PICGUG"), SET II
DOCKET NO. R-2017-2586783

d. Please see response to part (a) above.

Response Provided by: Philip Q Hanser, Principal of The Brattle Group
Part (c): Douglas A. Moser, Executive Vice President, Acting Chief Operating Officer, PGW

Dated: May 5, 2017

**Response of Philadelphia Gas Works ("PGW")
to the Interrogatories of the Office of Small Business Advocate ("OSBA"), Set I in
Docket No. R-2017-2586783**

Request: OSBA-I-31 Reference PGW Statement No. 7, pages 27 to 37, IT Rates:

A. Please explain why the Company does not allocate costs separately to Rate GTS and Rate IT customers in the cost allocation study.

B. Please explain how design day demand for Rate IT customers is reflected in the cost allocation study with respect to mains cost allocation. If design day demand for Rate IT customers is not included in the cost allocation study, please provide the Company's estimate of test year design day demand for Rate IT customers, as well as the maximum actual daily demand from Rate IT customers served by PGW over the past three years.

C. Please specify the "equivalent firm transportation rate" that would serve as the upper bound of the rate range for Rate IT customers.

D. Please estimate PGW's investment requirement to provide service to Rate IT customers if they were to convert to firm service, with supporting calculations. In effect, what is PGW's avoided cost associated with the interruptibility of Rate IT customers.

E. Regarding the discussion at the top of page 30 regarding the need to interrupt Rate IT customers, are rate IT customers obligated to deliver their daily requirements on peak days to the city gate? If so, please explain why Rate IT customers may be constrained by LNG capacity.

F. Also regarding the discussion at the top of page 30 regarding the need to interrupt Rate IT customers on peak days, please specify the costs that are avoided by the interruption. Specifically, are PGW's avoided costs related to the interruptibility of Rate IT customers a result of a need to increase deliverability capacity to the city gate, or are the avoided costs related to a need to expand or modify the distribution system?

Response: A. I have treated Rate GTS and Rate IT as a single class at the direction of the Company. The Company provided this direction because, at the time of filing, there were only three GTS customers (which are large volume legacy transportation customers). Additionally, as of the date of this response, only two GTS customer remain because one ceased operations in April 2017.

B. Design day demand for Rate IT does not enter into my computations. PGW does not include any demand from interruptible customers when calculating its design day demand and, therefore, does not estimate design day demand for interruptible customers.

C. The current delivery charge for firm transportation customers per MCF is as follows:

Commercial GS	$4.5984
Industrial GS	$4.5332
Phila. Housing Authority	$4.1101
Municipal (MS)	$3.3661

D. If Rate IT customers converted to firm service, there would be an increase need of system supply. This increase in volume would be met with a combination pipeline firm transportation, expansion of city gate capacity, expansion of PGW distribution system infrastructure and/or additional LNG capability. The exact mix would need additional studies to finalize.

E. Rate IT suppliers operate within PGW's Tariff Rate DB. There is a Daily Imbalance Surcharge and Monthly Imbalance Reconciliation. When PGW firm service customer send out demand exceeds PGW pipeline and off-site storage deliverability, requiring LNG to supplement firm send out, a Rate IT supplier that under delivers during these periods (meaning delivers less than their customers' actual demand), LNG would be required to meet this demand.

F. The costs are those identified in Part D.

Response Provided by: Kenneth S. Dybalski, Vice President - Energy Planning & Technical Compliance, PGW
Philip Q Hanser, Principal of The Brattle Group
Douglas A. Moser, Executive Vice President, Acting Chief Financial Officer, PGW

Dated: April 20, 2017

RESPONSE OF PHILADELPHIA GAS WORKS ("PGW") TO THE INTERROGATORIES OF PHILADELPHIA INDUSTRIAL AND COMMERCIAL GAS USERS GROUP ("PICGUG"), SET I
DOCKET NO. R-2017-2586783

Request: PICGUG-I-5: Please confirm the number of customers currently served under Rate GTS Firm, as well as the volume of natural gas transported by each identified customer.

Response: PGW has 2 GTS customers at the same service address which are provided transportation service pursuant to a special contract. There was a third GTS customer which ceased operations during April 2017. The total GTS volumes for all three customers which are included in the FPFTY = 13,176,839 Mcf. These volumes should be adjusted downward in order to account for the GTS customer which ceased operations. The adjusted volumes for the 2 remaining GTS customers are 12,057,211 Mcf.

Response Provided by: Douglas A. Moser, Executive Vice President, Acting Chief Operating Officer, PGW

Dated: April 28, 2017

REPORT TO THE RÉGIE DE L'ÉNERGIE ON

ANALYSIS OF LONG RUN MARGINAL COST OF SERVICE DELIVERY

Prepared by
Richard Baudino

J. Kennedy and Associates, Inc.
Roswell, GA

March 16, 2017

R-3867-2013
Phase 3A

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REPORT TO THE RÉGIE DE L'ÉNERGIE ON ANALYSIS OF LONG RUN MARGINAL COST OF SERVICE DELIVERY

1. Introduction

My name is Richard Baudino, consultant with J. Kennedy and Associates, Inc. I was retained by the Fédération canadienne de l'entreprise indépendante (FCEI) as an expert witness in file R-3867-2013 phase 3A. My mandate is to review the long-run marginal cost studies presented by Gaz Metro (GM) and Black and Veatch (B&V) and to make recommendations regarding the long run marginal operating and maintenance (O&M) costs for Gaz Metro.

In D-2016-106, the Régie de l'énergie (the "Régie") divided consideration of Gaz Metro's profitability analysis into two phases: Phase 3A considers "the method of determining the marginal costs of long-term service delivery"; Phase 3B considers the "methodology for evaluating the cost-effectiveness of network extension projects".

This report will thus focus on the long-run marginal O&M costs related to a service connection, evaluate the studies proffered by Gaz Metro and Black and Veatch, and recommend a method for the Régie to determine the marginal costs of long-term service delivery.

In preparing this report to the Régie, I reviewed the following material:

- English translation of the Régie's relevant decisions bearing on Phase 3A and 3B, including D-2016-169, D-2013-106, and D-2017-009.
- The study submitted by GM entitled "The Study Of The Marginal Costs Of Long-Term Service Delivery Applied To The Profitability Analysis (Follow-Up To Decisions D-2013-106 and D-2015-048)", October 4, 2016.

- The study submitted by B&V entitled "Marginal Costs of Long Term Service Delivery", October 4, 2016.
- The report entitled "Methodology For Evaluating The Profitability of System Extension Projects" from Gaz Metro dated February 16, 2017.
- English translation of information requests and responses submitted by the Régie and the intervenors.
- Other associated background material.

I also participated in a working group that the Régie created consisting of consultants for GM, FCEI, the ROEE, and the OC. This was a highly productive process and greatly informed the preparation and writing of this report. Dr. Edwin Overcast prepared a group report that provided the findings and conclusions of the group. My report is consistent with the agreements in the group report and presents my additional findings and conclusions separately.

2. Short-Run Marginal Costs (SRMC) and Long-Run Marginal Costs (LRMC)

In its decision D-2013-106, Phase 2, the Régie agreed with FCEI that it is appropriate to evaluate LRMC with respect to GM's profitability analyses. Specifically, the Régie found the following:

"[26] The Régie concurs with the FCEI's opinion regarding the use of long-term marginal costs. As the profitability analysis of the development plan bears on a 40-year period, it would seem logical to use long-term costs. The Régie believes that in the absence of a precise evaluation of long-term marginal operating costs, it would be expedient to retain the value of $157, as proposed by the FCEI."

The application of LRMC to the regulation of public utilities was described by Dr. Charles F. Phillips as follows:

"Put another way, price-output decisions should be governed by short-run marginal costs. Such costs, however, are extremely volatile. As the volume of output expands, for example, short-run marginal costs change more rapidly than do average costs. Rates, in turn would have to be changed frequently in accordance with variations in the volume of output. *Further, it is long-run marginal costs that should govern investment decisions.* (italics added)

There is a variant of the theoretical marginal cost principle that has greater practical application; that is, the long-run incremental cost (LRIC) concept. This concept, unlike the concept of short-run marginal cost, recognizes that utilities add capacity in discrete units and on a continuous basis. The long-run incremental cost concept thus includes the future costs of supplying utility services, as opposed to the average cost of serving existing customers."[1]

Alternatively, B&V's study stated the following on page 3:

"Essentially B&V concludes that the Gaz Metro exercise of estimating these O&M marginal costs to comply with the regulatory requirements overstates the actual long-run marginal costs and unduly burdens line extension policies to the detriment of all existing customers.

Economic theory holds that efficient prices equal short-run marginal cost not long-run marginal costs. The use of long-run marginal cost to evaluate line extension creates a timing mismatch between costs for ratemaking (the first year carrying costs that will be in revenue requirement) and the levelized costs over the life of the assets used in calculating long-run marginal costs. This timing mismatch raises revenue requirements in the short-run but over time reduces the revenue requirement for economic connections of new customers."

1 Charles F. Phillips, Jr., *The Regulation of Public Utilities*, Public Utilities Reports, Inc., 1993, 444.

Though B&V takes a contrary view, the finding of the Régie is indeed consistent with economic theory as applied to LRMC pricing for utilities in general and, specifically for Gaz Metro. In fact, LRMC is a superior measure to SRMC given the lumpiness of capacity additions by utilities and the inability of SRMC to properly reflect those additions.

This report to the Régie takes the perspective that long-run marginal operating costs should include all costs associated with adding new load over time. With respect to the relevant period over which LRMC may be measured, Dr. Phillips provided additional guidance, citing Dr. Alfred Kahn:

"The relevant future time frame is largely a matter of judgment. Argues Kahn:

> What we are trying to measure is how costs will differ, after a span of time sufficiently long for the system planners to adapt the supplying system to the change, by virtue of taking on some specified incremental block of sales on a continuing basis, as compared with not taking it on. Measurement is, to be sure, another matter. What I suspect we are likely to have, mainly, is a measure of the average, full additional costs, for all additional sales undertaken on a continuing basis, over whatever is the reasonable period for additions to capacity – possibly on the order of then to twelve years for electricity, perhaps three to five years in communications."[2]

The 40-year horizon considered by GM and the Régie is certainly consistent with LRMC. Over this period, the utility will not only be adding new customers through line extensions on its existing system, it will also likely expand its entire system, including capacity such as distribution mains. LRMC studies would measure the marginal costs of adding capacity as well as the impacts on all operating costs. However, in Phase 3A we do not have such a study available and Gaz Metro has not performed such a study.[3]

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[2] Phillips, 444 – 445.
[3] See Gaz Metro's response to Mr. Chernick's Information Request No. 2.2

Therefore, the perspective of Phase 3A will be to examine long run marginal costs associated with the service extensions irrespective of the long run marginal costs associated with upstream capacity. I recommend that the Régie more fully evaluate the O&M costs associated with capacity additions in Phase 3B.

3. Long-Run Marginal Cost of Service Delivery in the Gaz Metro and B&V Studies

On page 5 of 10 in Section 3.1 of the original Gaz Metro study, the marginal cost of service delivery was defined as "the set of costs that can be linked to a customer once he or she has agreed to become a Gaz metro customer. It includes the marginal costs the customer generates and the associated internal costs for the maintenance of its facilities and the services that are directly supplied." Gaz Metro further described its methodology for measuring those costs and in the Appendices presented the results of its analyses for the Residential, Commercial, Institutional, and Industrial (CII), and Major Industries markets.

In Section 3.2 of the original Gaz Metro study, the Company noted that it found differences between the costs associated with service delivery in the first year, and the cost for subsequent years because some of the activities occur only in the first year while others are ongoing. The marginal costs presented in Appendix 1 set forth the categories of costs measured by Gaz Metro for "Year 1" and "Year 2+".

The B&V study used Gaz Metro's original study as a basis for its study and eliminated certain costs that in the view of B&V did not properly constitute long-run marginal costs. Page 4 of the B&V study noted the following:

"Black & Veatch has used its economic, planning, and operating experience and expertise to evaluate and review the O&M costs as required by the Régie for reasonableness despite our reservations that such costs are not properly considered part of the line extension policy as discussed above. In any event for new facilities, these costs rarely occur at the margin in the near term and certainly are zero for plant O&M and even some customer services in the early years. This conclusion recognizes the importance of scale economies and lumpy additions as the relate to determining marginal costs."

The B&V study recommended changes described on page 8. Those changes are summarized as follows:

- Removed cost of reading a meter
- Removed cost of processing a standard customer call in Year 1
- Removed bad debt and collection and recovery costs
- Preventive and corrective maintenance on service lines – recommended zero for Year 1 and zero for the minimum for Year 2+
- Removed customer retention costs from the CII and Major Industries classes

Gaz Metro adopted the modification in the B&V study.[4]

4. Response to the Original GM study and the B&V Study and Recommendations to the Régie

Reviewing the approach taken in the original GM study, I recommend that the Régie use the methodology contained in that study as a reasonable starting point for measuring the marginal costs of long-term service delivery. GM's approach is an improvement to using the $157 value for marginal costs for all markets, as GM estimated and quantified the marginal cost of activities needed to connect a customer to its system. Using the "Year 1" and "Year 2+" framework enabled further refinement with respect to costs that recur each year and costs that only occur in the first year that a new customer is connected to the system. GM's analysis also evaluated marginal costs by major market, rather than making the simplifying assumption that the marginal cost was the same for all customers, small and large. GM also proposes to further refine its analysis on a project specific

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4 *Study of the Marginal Costs of Long-Term Service Delivery Applied to the Profitability Analysis, (Follow-Up to Decisions D-2013-106 and D-2015-048),* Oct. 4, 2016.

basis. This is another enhancement compared to its previous methodology. This general methodological approach should assist the Régie in developing line extension charges and customer charges in Phase 3B and future proceedings.

With respect to the cost items that were removed in the B&V report and listed previously, I recommend that they be added back in except for customer retention costs. In general, the B&V report does not take enough of a long run perspective and focuses on short run and near term effect of costs associated with line extensions. It may be the case that in the near term, existing capacity can accommodate a single new customer at zero marginal cost for such items as meter reading. However, over the longer term, with system expansion enough new customers will incur marginal meter reading costs. A long run analyses needs to capture such a cost.

I recommend including the following costs:

- Cost of reading a meter – Meter reading costs may increase in a stepwise manner as stated in the B&V report, but this should be captured in a long run marginal cost analysis. Although it may be correct that a single customer is unlikely to increase current meter reading costs, enough new customers added over time are likely to increase these costs. Omitting meter reading costs would understate the long run marginal operating costs.
- Cost of processing a standard customer call – On page 8, B&V asserted that "not all customers make calls to the utility so we recommend changing the minimum range to zero." Since a long run marginal cost analysis estimates incremental costs over time, the cost of processing customer calls must be included, as it is a valid and necessary expense in providing customer service over time. Even if a one new customer does not call the utility, it is reasonable to assume that others will and the cost of processing these calls should be reflected in long run marginal operating costs.
- Bad debt and collection and recovery costs – Bad debt write-offs and collection and recovery costs are actual costs to the utility and should be reflected in long

run marginal operating costs. Once again, as the system expands over time, these costs will increase on the margin as new customers are added. One customer may not increase bad debt and/or collection costs, but some incremental block of customers will over time.

- Preventive and Corrective Maintenance – These maintenance expenses should reflect long run costs of the system over time and should be included in operating expenses in all years.

A comparison between the B&V report and my recommendations are contained in Tables 1 – 3 at the end of this report. I agree with the B&V recommendation on page 7 that the numbers should be updated for current costs if approved for use.

Tables 1 – 3 note that the numbers do not contain long run marginal costs associated with distribution mains O&M. As GM's system expands over the longer term, additional O&M costs will likely be incurred to meet the additional loads placed on the system. This component of O&M should be included. I recommend that these O&M costs be evaluate in Phase 3B.

Regarding customer retention costs, it is not clear at this point as to the elements that constitute these retention costs and whether these costs should be included in the marginal costs of long term delivery service. I sought additional support for these costs in my Information Request No. 8 (e). Gaz Metro responded with references to its response to question 1.1 of the Régie's request for information No. 5 and its response to question 1.4 of Mr. Chernick's information request. However, these referenced responses did not provide the additional details I required. Therefore, I did not include customer retention costs in my recommendation to the Régie.

Other Considerations

In its study filed on October 4, 2016, GM showed a comparison between the profitability results using the B&V study and GM's original study. The bottom line results were very close between the two studies, showing that the exclusions in the B&V report did not affect the profitability results in a significant way.

In addition, since the expected marginal costs for small customers are lower than for larger customers, it makes intuitive sense that the Residential profitability results would improve compared to using the $157 marginal cost proxy that was used by Gaz Metro in the past.

5. Summary of Results of Consultants Working Group

The Régie ordered that the consultants for the intervenors and Gaz Metro meet as a working group to see if there could be agreement on the components to include in marginal costs of long-term service. The group met on several occasions and agreed on several cost components to include in marginal costs for the purposes of a profitability analysis. This agreement is captured in a separate document, which was prepared by Dr. Overcast.

I found the group approach to be very productive and helpful in evaluating and understanding different perspectives on marginal cost of long term service delivery for Gaz Metro. I appreciate the Régie for providing the consultants with an opportunity to candidly share their views and achieve an agreement on many aspects of the GM and B&V studies.

As this report mentioned earlier, marginal distribution mains O&M costs should be considered in Phase 3B. Given that capital costs will be dealt with in Phase 3B, it was logical to consider distribution mains O&M in that forum. I recommend that marginal distribution mains O&M be included in the marginal costs of long-term service delivery.

TABLE 1
RESIDENTIAL LONG RUN MARGINAL COSTS - OPERATING EXPENSES

		Black and Veatch Proposed				Baudino Proposed			
		Year 1		Year 2 and +		Year 1		Year 2 and +	
		Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
1	Mailing of subscription confirmation letter	$ 0.83	$ 0.83	$ -	$ -	$ 0.83	$ 0.83	$ -	$ -
2	Cost of mailing bill	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36
3	Cost of opening a billing file	$ 9.66	$ 9.66	$ -	$ -	$ 9.66	$ 9.66	$ -	$ -
4	Cost of reading a meter	$ -	$ -	$ -	$ -	$ 6.71	$ 6.71	$ 6.71	$ 6.71
5	Input of a new contract	$ 36.29	$ 36.29	$ -	$ -	$ 36.29	$ 36.29	$ -	$ -
6	Cost of a credit check conducted internally	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Annual cost of cashing a payment	$ 0.74	$ 0.74	$ 0.74	$ 0.74	$ 0.74	$ 0.74	$ 0.74	$ 0.74
8	Cost of processing a standard customer call	$ -	$ 12.84	$ -	$ 12.84	$ 12.84	$ 12.84	$ 12.84	$ 12.84
9	Cost of bad debt	$ -	$ -	$ -	$ -	$ 0.57	$ 0.57	$ 0.57	$ 0.57
10	Collection and recovery costs	$ -	$ -	$ -	$ -	$ 2.43	$ 2.43	$ 2.43	$ 2.43
11	Customer retention costs - Major accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Customer retention costs - Major industries	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Preventive maintenance - Service line	$ -	$ -	$ -	$ 12.88	$ 12.88	$ 12.88	$ 12.88	$ 12.88
14	Corrective maintenance - Service line	$ -	$ -	$ -	$ 17.99	$ 17.99	$ 17.99	$ 17.99	$ 17.99
15	Processing of CRP application	$ -	$ 23.83	$ -	$ -	$ -	$ 23.83	$ -	$ -
16	Preventive maintenance - Mains	$0.22 / m				$0.22 / m			
17	Corrective maintenance - Mains	$0.37 / m				$0.37 / m			
18	Meter inspection and maintenance costs								
19	- Types of meters								
20	Turbine	$ -	$ 31.68	$ -	$ 31.68	$ -	$ 31.68	$ -	$ 31.68
21	Spin test for turbines (less than 12 in.)	$ -	$ 79.20	$ -	$ 79.20	$ -	$ 79.20	$ -	$ 79.20
22	Telemetry	$ -	$ 118.79	$ -	$ 118.79	$ -	$ 118.79	$ -	$ 118.79
23	Corrective instruments	$ -	$ 87.11	$ -	$ 87.11	$ -	$ 87.11	$ -	$ 87.11
24	Spin test for turbine (12 in and more)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Cost of a cellular line - telemetry	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Totals	$ 55.88	$ 409.33	$ 9.10	$ 369.59	$ 109.30	$ 449.91	$ 62.52	$ 379.30

Note: This table does not reflect Distribution Mains O&M costs, which will be included in Phase 3B

TABLE 2
CII LONG RUN MARGINAL COSTS - OPERATING EXPENSES

		Black and Veatch Proposed				Baudino Proposed			
		Year 1		Year 2 and +		Year 1		Year 2 and +	
		Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
1	Mailing of subscription confirmation letter	$ 0.83	$ 0.83	$ -	$ -	$ 0.83	$ 0.83	$ -	$ -
2	Cost of mailing bill	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36
3	Cost of opening a billing file	$ 9.66	$ 9.66	$ -	$ -	$ 9.66	$ 9.66	$ -	$ -
4	Cost of reading a meter	$ -	$ -	$ -	$ -	$ 6.71	$ 6.71	$ 6.71	$ 6.71
5	Input of a new contract	$ 52.62	$ 52.62	$ -	$ -	$ 52.62	$ 52.62	$ -	$ -
6	Cost of a credit check conducted internally	$ 17.19	$ 17.19	$ -	$ -	$ 17.19	$ 17.19	$ -	$ -
7	Annual cost of cashing a payment	$ 1.75	$ 1.75	$ 1.75	$ 1.75	$ 1.75	$ 1.75	$ 1.75	$ 1.75
8	Cost of processing a standard customer call	$ -	$ 12.84	$ -	$ 12.84	$ 12.84	$ 12.84	$ 12.84	$ 12.84
9	Cost of bad debt	$ -	$ -	$ -	$ -	$ 7.77	$ 7.77	$ 7.77	$ 7.77
10	Collection and recovery costs	$ -	$ -	$ -	$ -	$ 33.31	$ 33.31	$ 33.31	$ 33.31
11	Customer retention costs - Major accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Customer retention costs - Major industries	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Preventive maintenance - Service line	$ -	$ -	$ -	$ 12.88	$ 12.88	$ 12.88	$ 12.88	$ 12.88
14	Corrective maintenance - Service line	$ -	$ -	$ -	$ 17.99	$ 17.99	$ 17.99	$ 17.99	$ 17.99
15	Processing of CRP application	$ -	$ 32.90	$ -	$ -	$ -	$ 32.90	$ -	$ -
16	Preventive maintenance - Mains	$0.22 / m				$0.22 / m			
17	Corrective maintenance - Mains	$0.37 / m				$0.37 / m			
18	Meter inspection and maintenance costs								
19	- Types of meters								
20	Turbine	$ -	$ 31.68	$ -	$ 31.68	$ -	$ 31.68	$ -	$ 31.68
21	Spin test for turbines (less than 12 in.)	$ -	$ 79.20	$ -	$ 79.20	$ -	$ 79.20	$ -	$ 79.20
22	Telemetry	$ -	$ 118.79	$ -	$ 118.79	$ -	$ 118.79	$ -	$ 118.79
23	Corrective instruments	$ -	$ 87.11	$ -	$ 87.11	$ -	$ 87.11	$ -	$ 87.11
24	Spin test for turbine (12 in and more)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Cost of a cellular line - telemetry	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Totals	$ 90.41	$ 452.93	$ 10.11	$ 370.60	$ 181.91	$ 531.59	$ 101.61	$ 418.39

Note: This table does not reflect Distribution Mains O&M costs, which will be included in Phase 3B

TABLE 3
MAJOR INDUSTRIES LONG RUN MARGINAL COSTS - OPERATING EXPENSES

		Black and Veatch Proposed				Baudino Proposed			
		Year 1		Year 2 and +		Year 1		Year 2 and +	
		Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
1	Mailing of subscription confirmation letter	$ 0.83	$ 0.83	$ -	$ -	$ 0.83	$ 0.83	$ -	$ -
2	Cost of mailing bill	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36
3	Cost of opening a billing file	$ 9.66	$ 9.66	$ -	$ -	$ 9.66	$ 9.66	$ -	$ -
4	Cost of reading a meter	$ -	$ -	$ -	$ -	$ 6.71	$ 6.71	$ 6.71	$ 6.71
5	Input of a new contract	$ 36.29	$ 36.29	$ -	$ -	$ 36.29	$ 36.29	$ -	$ -
6	Cost of a credit check conducted internally	$ 17.19	$ 17.19	$ -	$ -	$ 17.19	$ 17.19	$ -	$ -
7	Annual cost of cashing a payment	$ 1.59	$ 1.59	$ 1.59	$ 1.59	$ 1.59	$ 1.59	$ 1.59	$ 1.59
8	Cost of processing a standard customer call	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Cost of bad debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Collection and recovery costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Customer retention costs - Major accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Customer retention costs - Major industries	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Preventive maintenance - Service line	$ -	$ -	$ -	$ 12.88	$ 12.88	$ 12.88	$ 12.88	$ 12.88
14	Corrective maintenance - Service line	$ -	$ -	$ -	$ 17.99	$ 17.99	$ 17.99	$ 17.99	$ 17.99
15	Processing of CRP application	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Preventive maintenance - Mains	$0.22 / m				$0.22 / m			
17	Corrective maintenance - Mains	$0.37 / m				$0.37 / m			
18	Meter inspection and maintenance costs								
19	- Types of meters								
20	Turbine	$ 31.68	$ 31.68	$ 31.68	$ 31.68	$ 31.68	$ 31.68	$ 31.68	$ 31.68
21	Spin test for turbines (less than 12 in.)	$ 79.20	$ -	$ 79.20	$ -	$ 79.20	$ -	$ 79.20	$ -
22	Telemetry	$ 118.79	$ 118.79	$ 118.79	$ 118.79	$ 118.79	$ 118.79	$ 118.79	$ 118.79
23	Corrective instruments	$ 87.11	$ 87.11	$ 87.11	$ 87.11	$ 87.11	$ 87.11	$ 87.11	$ 87.11
24	Spin test for turbine (12 in and more)	$ -	$ 237.59	$ -	$ 237.59	$ -	$ 237.59	$ -	$ 237.59
25	Cost of a cellular line - telemetry	$ -	$ 186.12	$ -	$ 186.12	$ -	$ 186.12	$ -	$ 186.12
26	Totals	$ 390.70	$ 735.21	$ 326.73	$ 702.11	$ 428.28	$ 772.79	$ 364.31	$ 708.82

Note: This table does not reflect Distribution Mains O&M costs, which will be included in Phase 3B