STOLL, KEENON & PARK, LLP

201 EAST MAIN STREET
SUITE 1000
LEXINGTON, KENTUCKY 40507-1380

(606) 231-3000
FAX: (606) 253-1093

*FRANKFORT OFFICE:
307 WASHINGTON STREET
FRANKFORT, KY. 40601-1823
(502) 875-6220
FAX: (502) 875-6235

**WESTERN KENTUCKY OFFICE:
201 C NORTH MAIN STREET
HENDERSON, KY. 42420-3103
(502) 831-1900
FAX: (502) 827-4060

***LOUISVILLE OFFICE:
2650 AEGON CENTER
400 WEST MARKET
LOUISVILLE, KY. 40202-3377
(502) 568-9100
FAX: (502) 568-5700

INTERNET: www.skp.com

JUL 15 1999
PUBLIC SERVICE COMMISSION

July 15, 1999

Hon. Helen Helton
Executive Director
Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602

Re: Delta Natural Gas Company, Inc.
Case No. 99-046

Dear Ms. Helton:

We enclose for filing an original and eight (8) copies of the Responses of Delta Natural Gas Company, Inc. to Attorney General's Request for Information dated July 2, 1999, and the PSC Data Request dated July 2, 1999, in the above-captioned case. We would appreciate your placing these papers with the other papers in this case. Thank you for your kind assistance in connection with this matter.

Sincerely,

Robert Watt

Robert M. Watt, III

rmw
encl.
cc: Mr. John F. Hall (w/encl.)
Counsel of Record (w/encl.)

1. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 1(a). Identify the portions of Delta's Response to the Attorney General's Data Request, Item 93, that address why Delta has been unable to earn its authorized rate of return over the last 10 years.

RESPONSE:

Delta prepares a fiscal budget annually and monitors actual results versus budget on a monthly basis. Each year when budgets are prepared Delta considers whether rates are adequate to earn Delta's authorized return, and whether a rate case should be filed. This budget process, which was referenced in Delta's Response to the Attorney General's Data Request, Item 93, is where Delta analyzes and reviews all revenues, expenses and capital expenditure plans. At that time, Delta considers why it has not been able to earn its authorized return and takes appropriate action.

For example, this past March – April, Delta reviewed results through fiscal 1999 to to-date, developed budgets for fiscal 2000 and evaluated why it had not been able to earn its authorized rate of return. Part of the reason was weather, as actual billed degree days were only 79% of normal at March 31, 1999 and sales volumes were 600,000 Mcf less than planned. Additionally, increased costs and investment led Delta to file Rate Case No. 99-176 in order to provide for an adequate return in the future.

WITNESS:

John Hall

2. In its Response to the Commission's Order of June 4, 1999, Item 1(a), Delta stated that "Delta has not performed any formal analyses" of its finances and operations to determine why Delta has been unable to earn its authorized rate of return over the last 10 years. Why have no analyses been performed?

RESPONSE:

Delta does continuous analyses on a monthly basis of budget versus actual, and annually when budgets for the next fiscal year are prepared. These are not normally referred to as "analyses". They are a part of Delta's ongoing routine management of the Company, also see Delta's Response to Item 1.

WITNESS:

John Hall

Notes

3

3. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 2. Provide references to the line items contained on Delta's Federal Energy Regulatory Commission ("FERC") Form 2 financial statements that support the earned rate of return calculation contained in Delta's response. If the information necessary to calculate the earned rate of return is not segregated on these financial statements, provide the detailed information for each year listed in Delta's Response.

RESPONSE:

The information came from Delta's fiscal year end annual reports. Attached are the income statements and balance sheets for 1987 through 1998.

WITNESS:

John Hall

Consolidated Statements of Income

For the Years Ended June 30,	1998	1997	1996
Operating Revenues	$ 44,258,000	$ 42,169,185	$ 36,576,055
Operating Expenses			
Purchased gas	$ 22,499,488	$ 23,265,222	$ 17,389,755
Operation and maintenance (Note 1)	8,968,213	8,631,635	8,642,511
Depreciation and depletion (Note 1)	3,445,382	2,935,257	2,510,952
Taxes other than income taxes	1,212,058	1,056,689	1,036,282
Income taxes (Note 2)	1,401,000	964,800	1,559,500
Total operating expenses	$ 37,526,141	$ 36,853,603	$ 31,139,000
Operating Income	$ 6,731,859	$ 5,315,582	$ 5,437,055
Other Income and Deductions, Net	67,911	40,874	32,503
Income Before Interest Charges	$ 6,799,770	$ 5,356,456	$ 5,469,558
Interest Charges			
Interest on long-term debt	$ 3,326,681	$ 2,997,393	$ 1,851,768
Other interest	897,265	519,432	867,641
Amortization of debt expense	124,552	115,366	88,800
Total interest charges	$ 4,348,498	$ 3,632,191	$ 2,808,209
Net Income	$ 2,451,272	$ 1,724,265	$ 2,661,349
Weighted Average Number of Common Shares Outstanding	2,359,598	2,294,134	1,886,629
Basic and Diluted Earnings Per Common Share	$ 1.04	$ .75	$ 1.41
Dividends Declared Per Common Share	$ 1.14	$ 1.14	$ 1.12

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Statements of Income

For the Years Ended June 30,	1995	1994	1993
Operating Revenues	$ 31,844,339	$ 34,846,941	$ 31,221,410
Operating Expenses			
Purchased gas	$ 15,497,156	$ 17,250,556	$ 14,234,258
Operation and maintenance (Note 1)	8,002,797	8,382,767	8,020,622
Depreciation and depletion (Note 1)	2,183,558	1,977,868	1,833,072
Taxes other than income taxes	863,340	875,477	797,942
Income taxes (Note 1)	1,042,400	1,509,600	1,543,700
Total operating expenses	$ 27,589,251	$ 29,996,268	$ 26,429,594
Operating Income	$ 4,255,088	$ 4,850,673	$ 4,791,816
Other Income and Deductions, Net	50,582	34,987	39,681
Income Before Interest Charges	$ 4,305,670	$ 4,885,660	$ 4,831,497
Interest Charges			
Interest on long-term debt	$ 1,879,442	$ 1,879,526	$ 1,875,901
Other interest	419,693	243,729	258,405
Amortization of debt expense	88,800	91,404	76,527
Total interest charges	$ 2,387,935	$ 2,214,659	$ 2,210,833
Net Income	$ 1,917,735	$ 2,671,001	$ 2,620,664
Weighted Average Number of Common Shares Outstanding	1,850,986	1,775,068	1,635,945
Earnings Per Common Share	$ 1.04	$ 1.50	$ 1.60
Dividends Declared Per Common Share	$ 1.12	$ 1.105	$ 1.085

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Statements of Income

For the Years Ended June 30,	1992	1991	1990
Operating Revenues	$29,200,834	$26,778,255	$27,182,104
Operating Expenses			
Purchased gas	$12,564,947	$13,422,087	$13,952,663
Operation and maintenance	8,173,070	7,230,284	7,293,037
Depreciation and depletion (Note 1)	1,675,540	1,788,944	1,746,083
Taxes other than income taxes	759,354	737,395	661,883
Income taxes (Note 1)	1,441,600	560,500	608,200
Total operating expenses	$24,614,511	$23,739,210	$24,261,866
Operating Income	$ 4,586,323	$ 3,039,045	$ 2,920,238
Other Income and Deductions, Net	34,087	91,927	33,046
Income Before Interest Charges	$ 4,620,410	$ 3,130,972	$ 2,953,284
Interest Charges			
Interest on long-term debt	$ 1,938,389	$ 1,251,580	$ 1,180,411
Other interest	152,728	663,314	527,885
Amortization of debt expense	75,480	53,496	49,476
Total interest charges	$ 2,166,597	$ 1,968,390	$ 1,757,772
Net Income	$ 2,453,813	$ 1,162,582	$ 1,195,512
Weighted Average Number of Common Shares Outstanding	1,612,437	1,586,235	1,563,588
Earnings Per Common Share	$ 1.52	$ .73	$ .76
Dividends Declared Per Common Share	$ 1.08	$ 1.08	$ 1.08

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended June 30,	1989	1988	1987
Operating Revenues	**$25,684,018**	$23,501,834	$24,650,607
Operating Expenses			
Purchased gas	**$13,013,341**	$11,082,140	$12,850,562
Operation and maintenance	**6,702,370**	6,567,805	6,229,100
Depreciation	**1,535,300**	1,436,227	1,312,611
Taxes other than income taxes	**597,179**	570,477	538,804
Income taxes (Note 1)	**789,800**	810,000	1,206,000
Total operating expenses	**$22,637,990**	$20,466,649	$22,137,077
Operating Income	**$ 3,046,028**	$ 3,035,185	$ 2,513,530
Other Income and Deductions, Net	**20,718**	14,130	13,359
Income Before Interest Charges	**$ 3,066,746**	$ 3,049,315	$ 2,526,889
Interest Charges			
Interest on long-term debt	**$ 1,236,735**	$ 1,274,372	$ 691,501
Other interest	**245,458**	249,819	424,166
Amortization of debt expense	**49,476**	49,595	28,984
Total interest charges	**$ 1,531,669**	$ 1,573,786	$ 1,144,651
Net Income	**$ 1,535,077**	$ 1,475,529	$ 1,382,238
Preferred dividends (Note 5)	—	—	111,643
Earnings on Common Shares	**$ 1,535,077**	$ 1,475,529	$ 1,270,595
Weighted Average Number of Common Shares Outstanding	**1,430,608**	1,145,354	1,139,851
Earnings Per Common Share	**$ 1.07**	$ 1.29	$ 1.11
Dividends Declared Per Common Share	**$ 1.07**	$ 1.04	$ 1.04

The accompanying notes are an integral part of these financial statements.

Consolidated Balance Sheets

As of June 30,		1998		1997
Assets				
Gas Utility Plant, at cost	$	127,028,159	$	116,829,158
Less - Accumulated provision for depreciation		(34,929,481)		(31,734,976)
Net gas plant	$	92,098,678	$	85,094,182
Current Assets				
Cash and cash equivalents	$	118,536	$	480,423
Accounts receivable, less accumulated provisions for doubtful accounts of $120,002 and $113,945 in 1998 and 1997, respectively		2,538,800		2,414,632
Gas in storage, at average cost		2,050,000		1,209,171
Deferred gas costs (Note 1)		–		2,180,606
Materials and supplies, at first-in, first-out cost		520,362		773,108
Prepayments		241,731		312,379
Total current assets	$	5,469,429	$	7,370,319
Other Assets				
Cash surrender value of officers' life insurance (face amount of $1,036,009)	$	339,215	$	321,339
Note receivable from officer		110,000		134,000
Unamortized debt expense and other (Note 6)		4,849,291		3,761,325
Total other assets	$	5,298,506	$	4,216,664
Total assets	$	102,866,613	$	96,681,165
Liabilities and Shareholders' Equity				
Capitalization (See Consolidated Statements of Capitalization)				
Common shareholders' equity	$	29,810,294	$	29,474,569
Long-term debt (Notes 6 and 7)		52,612,494		38,107,860
Total capitalization	$	82,422,788	$	67,582,429
Current Liabilities				
Notes payable (Note 5)	$	1,875,000	$	10,865,000
Current portion of long-term debt (Notes 6 and 7)		1,790,000		1,987,600
Accounts payable		2,050,628		2,386,717
Accrued taxes		1,085,766		1,132,315
Refunds due customers		117,123		577,874
Advance recovery of gas costs (Note 1)		1,148,019		–
Customers' deposits		438,134		368,561
Accrued interest on debt		1,215,265		1,033,220
Accrued vacation		528,952		516,032
Other accrued liabilities		485,018		492,501
Total current liabilities	$	10,733,905	$	19,359,820
Deferred Credits and Other				
Deferred income taxes	$	8,023,475	$	7,921,100
Investment tax credits		637,300		708,400
Regulatory liability (Note 2)		831,425		892,100
Advances for construction and other		217,720		217,316
Total deferred credits and other	$	9,709,920	$	9,738,916
Commitments and Contingencies (Note 8)				
Total liabilities and shareholders' equity	$	102,866,613	$	96,681,165

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Balance Sheets

As of June 30,	1996	1995
Assets		
Gas Utility Plant, at cost	$ 98,795,623	$ 84,944,969
Less - Accumulated provision for depreciation	(26,749,774)	(24,588,203)
Net gas plant	$ 72,045,849	$ 60,356,766
Current Assets		
Cash and cash equivalents	$ 151,633	$ 135,779
Accounts receivable, less accumulated provisions for doubtful accounts of $105,756 and $81,608 in 1996 and 1995, respectively	2,096,454	1,236,199
Gas in storage, at average cost	427,164	490,710
Deferred gas costs (Note 1)	2,676,357	—
Materials and supplies, at first-in, first-out cost	652,139	527,442
Prepayments	369,544	423,246
Total current assets	$ 6,373,291	$ 2,813,376
Other Assets		
Cash surrender value of officers' life insurance (face amount of $1,036,009 and $1,044,355 in 1996 and 1995, respectively)	$ 304,339	$ 293,116
Note receivable from officer	126,000	130,000
Unamortized debt expense and other (Note 5)	2,291,158	2,355,458
Total other assets	$ 2,721,497	$ 2,778,574
Total assets	$ 81,140,637	$ 65,948,716
Liabilities and Shareholders' Equity		
Capitalization (See Consolidated Statements of Capitalization)		
Common shareholders' equity	$ 23,628,323	$ 22,511,513
Long-term debt (Notes 5 and 6)	24,488,916	23,702,200
Notes payable refinanced subsequent to yearend (Note 4)	18,075,000	—
Total capitalization	$ 66,192,239	$ 46,213,713
Current Liabilities		
Notes payable (Note 4)	$ —	$ 5,675,000
Current portion of long-term debt (Notes 5 and 6)	1,084,800	1,057,700
Accounts payable	2,826,438	1,955,231
Accrued taxes	93,554	363,948
Refunds due customers	23,354	479,637
Advance recovery of gas cost	—	1,111,786
Customers' deposits	304,246	331,708
Accrued interest on debt	637,596	473,001
Accrued vacation	485,847	454,728
Other accrued liabilities	238,571	349,872
Total current liabilities	$ 5,694,406	$ 12,252,611
Deferred Credits and Other		
Deferred income taxes	$ 7,318,500	$ 5,510,400
Investment tax credits	779,400	850,400
Regulatory liability (Note 1)	938,300	912,900
Advances for construction and other	217,792	208,692
Total deferred credits and other	$ 9,253,992	$ 7,482,392
Commitments and Contingencies (Note 7)		
Total liabilities and shareholders' equity	$ 81,140,637	$ 65,948,716

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Balance Sheets

As of June 30,	1994	1993
Assets		
Gas Utility Plant, at cost	$ 77,882,135	$ 71,187,860
Less - Accumulated provision for depreciation	(22,862,469)	(21,118,363)
Net gas plant	$ 55,019,666	$ 50,069,497
Current Assets		
Cash and cash equivalents	$ 156,547	$ 214,879
Accounts receivable, less accumulated provisions for doubtful accounts of $131,324 and $208,182 in 1994 and 1993, respectively	1,117,962	1,920,159
Gas in storage, at average cost	352,572	364,508
Deferred gas costs (Note 1)	1,471,342	99,312
Materials and supplies, at first-in, first-out cost	700,761	471,486
Prepayments	317,343	343,044
Total current assets	$ 4,116,527	$ 3,413,388
Other Assets		
Cash surrender value of officers' life insurance (face amount of $1,031,000 and $1,020,000 in 1994 and 1993, respectively)	$ 269,029	$ 244,313
Note receivable from officer	83,000	95,000
Unamortized debt expense and other (Note 5)	2,444,258	1,307,714
Total other assets	$ 2,796,287	$ 1,647,027
Total assets	$ 61,932,480	$ 55,129,912
Liabilities and Shareholders' Equity		
Capitalization (See Consolidated Statements of Capitalization)		
Common shareholders' equity	$ 22,164,791	$ 17,501,045
Long-term debt (Note 5)	24,500,000	19,596,401
Total capitalization	$ 46,664,791	$ 37,097,446
Current Liabilities		
Notes payable (Note 4)	$ 2,705,000	$ 6,470,000
Current portion of long-term debt (Note 5)	500,000	1,259,000
Accounts payable	2,133,840	1,620,575
Accrued taxes	436,158	470,701
Refunds due customers	396,065	37,795
Customers' deposits	342,979	377,402
Accrued interest on debt	427,338	445,788
Accrued vacation	454,362	420,675
Other accrued liabilities	314,888	257,027
Total current liabilities	$ 7,710,630	$ 11,358,963
Deferred Credits and Other		
Deferred income taxes	$ 5,116,400	$ 5,482,600
Investment tax credits	921,800	993,300
Regulatory liability (Note 1)	1,312,500	—
Advances for construction and other	206,359	197,603
Total deferred credits and other	$ 7,557,059	$ 6,673,503
Commitments and Contingencies (Note 6)		
Total liabilities and shareholders' equity	$ 61,932,480	$ 55,129,912

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Balance Sheets

As of June 30,	1992	1991
Assets		
Gas Utility Plant, at cost	$ 65,621,057	$ 61,346,506
Gas Plant Acquisition Adjustment	411,160	411,160
Less – Accumulated provision for depreciation	(19,925,308)	(18,483,944)
Net gas plant	$ 46,106,909	$ 43,273,722
Current Assets		
Cash and cash equivalents	$ 175,566	$ 126,175
Accounts receivable	1,212,554	1,555,977
Gas in storage, at average cost	280,706	205,664
Materials and supplies, at first-in, first-out cost	626,844	748,936
Prepayments	351,140	311,143
Total current assets	$ 2,646,810	$ 2,947,895
Other Assets		
Cash surrender value of officers' life insurance (face amount of $1,007,000 and $996,000 in 1992 and 1991, respectively)	$ 222,167	$ 193,506
Note receivable from officer	107,000	91,000
Unamortized debt expense and other (Note 5)	1,395,128	1,310,207
Total other assets	$ 1,724,295	$ 1,594,713
Total assets	$ 50,478,014	$ 47,816,330
Liabilities and Shareholders' Equity		
Capitalization (See Consolidated Statements of Capitalization)		
Common shareholders' equity	$ 16,227,158	$ 15,147,551
Long-term debt (Note 5)	20,187,826	21,473,431
Total capitalization	$ 36,414,984	$ 36,620,982
Current Liabilities		
Notes payable (Note 4)	$ 2,770,000	$ 1,855,000
Current portion of long-term debt (Note 5)	1,259,000	761,000
Accounts payable	1,181,678	756,780
Accrued taxes	633,683	336,315
Refunds due customers	569	21,321
Advance recovery of gas costs (Note 1)	893,824	429,954
Customers' deposits	380,314	340,338
Accrued interest on debt	418,650	481,588
Accrued vacation	399,718	381,537
Other accrued liabilities	285,775	494,588
Total current liabilities	$ 8,223,211	$ 5,858,421
Deferred Credits and Other		
Deferred income taxes	$ 4,571,700	$ 4,032,000
Investment tax credits	1,065,100	1,137,200
Advances for construction and other	203,019	167,727
Total deferred credits and other	$ 5,839,819	$ 5,336,927
Commitments and Contingencies (Note 6)		
Total liabilities and shareholders' equity	$ 50,478,014	$ 47,816,330

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS

As of June 30,	1990	1989
Assets		
Gas Utility Plant, at cost	$57,010,791	$51,215,646
Gas Plant Acquisition Adjustment	411,160	411,160
Less — Accumulated provision for depreciation	(17,130,067)	(15,588,709)
	$40,291,884	$36,038,097
Current Assets		
Cash and cash equivalents	$ 192,796	$ 256,167
Accounts receivable, less accumulated provisions for doubtful accounts of $41,599 and $70,038 in 1990 and 1989, respectively	1,199,244	1,359,408
Gas in storage, at average cost	286,667	319,285
Materials and supplies, at first-in, first-out cost	882,311	879,393
Prepayments	300,887	214,304
Deferred gas cost	—	27,402
	$ 2,861,905	$ 3,055,959
Other Assets		
Cash surrender value of officers' life insurance (face amount of $985,000 and $970,000 in 1990 and 1989, respectively)	$ 175,847	$ 163,863
Note receivable from officer	103,000	115,000
Unamortized debt expense (Note 5)	811,183	860,659
	$ 1,090,030	$ 1,139,522
	$44,243,819	$40,233,578

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS

As of June 30,	1990	1989
Liabilities And Shareholders' Equity		
Capitalization (See Consolidated Statements of Capitalization)		
Common shareholders' equity	$15,369,126	$15,663,078
Long-term debt (Note 5)	12,231,202	13,039,989
	$27,600,328	$28,703,067
Current Liabilities		
Notes payable (Note 4)	$ 6,850,000	$ 2,775,000
Current portion of long-term debt	782,800	779,800
Accounts payable	923,330	1,126,929
Accrued taxes	629,364	268,257
Refunds due customers	167,900	57,084
Advance recovery of gas costs (Note 1)	366,231	—
Customers' deposits	370,115	379,698
Accrued interest on debt	432,159	339,559
Accrued vacation	359,000	339,500
Other current and accrued liabilities	511,927	378,877
	$11,392,826	$ 6,444,704
Deferred Credits and Other		
Deferred income taxes	$ 3,877,100	$ 3,636,500
Investment tax credits	1,209,200	1,282,200
Deferred compensation	—	12,581
Advances for construction and other	164,365	154,526
	$ 5,250,665	$ 5,085,807
Commitments and Contingencies (Note 6)		
	$44,243,819	$40,233,578

The accompanying notes are an integral part of these financial statements.

Consolidated Balance Sheets

As of June 30,	1988	1987
Assets		
Gas Utility Plant, at cost	$46,334,262	$42,997,691
Gas Plant Acquisition Adjustments	411,160	411,160
Less - Accumulated provision for depreciation	(14,119,725)	(12,965,535)
	$32,625,697	$30,443,316
Current Assets		
Cash	$ 246,169	$ 275,501
Accounts receivable, less accumulated provision for doubtful accounts of $82,768 and $65,669 in 1988 and 1987, respectively	958,600	987,700
Gas in storage, at average cost	370,422	375,148
Materials and supplies, at first-in, first-out cost	635,650	618,603
Prepayments	251,344	292,995
	$ 2,462,185	$ 2,549,947
Other Assets		
Cash surrender value of officers' life insurance (face amount of $368,000 and $363,000 in 1988 and 1987, respectively)	$ 152,885	$ 142,121
Note receivable from officer	108,000	——
Unamortized debt expense and other (Note 4)	910,135	958,178
	$ 1,171,020	$ 1,100,299
	$36,258,902	$34,093,562
Liabilities and Shareholders' Equity		
Capitalization (See Consolidated Statements of Capitalization)		
Common shareholders' equity	$10,467,861	$10,112,614
Long-term debt (Note 4)	14,493,031	14,714,328
	$24,960,892	$24,826,942
Current Liabilities		
Notes payable (Note 3)	$ 3,450,000	$ 2,041,440
Current portion of long-term debt	75,000	73,300
Accounts payable	850,565	906,823
Accrued taxes	405,080	128,511
Refunds due customers	66,009	17,501
Advance recovery of gas costs (Note 1)	635,457	527,413
Customers' deposits	352,527	358,421
Accrued interest on debt	350,379	317,279
Accrued vacation	303,915	275,685
Other current and accrued liabilities	347,601	389,847
	$ 6,836,533	$ 5,036,220
Deferred Credits and Other		
Deferred income taxes	$ 2,926,600	$ 2,595,000
Investment tax credits	1,355,200	1,428,200
Deferred compensation	28,329	47,897
Advances for construction	151,348	159,303
	$ 4,461,477	$ 4,230,400
Contingencies (Note 6)		
	$36,258,902	$34,093,562

The accompanying notes are an integral part of these financial statements.

Notes

4

4. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 3.

a. Describe how the amount in "column (i), estimated marginal cost per customer" was determined. Provide the workpapers and supporting documents used to determine "column (i)."

b. Explain the differences between the marginal cost per customer and the net distribution plant increase per customer.

RESPONSE:

a. Column (i), estimated marginal cost per customer, was calculated by applying the Trend Function in a Microsoft Excel spreadsheet to first column on the spreadsheet (i.e., the column showing 1, 2, 3, ... ,11) and to column (h), net plant per additional customer. The Trend Function is a standard function in Excel that estimates a trend line by performing a least squares regression on the data. The function calculates the slope (m) and intercept (b) for a the following linear equation:

$$y = mx + b$$

and calculates an estimated value of the dependent variable y based on the value of the independent variable x.

Although there were no additional workpapers used in calculating column(i), we have attached hereto (1) a worksheet we have prepared showing the procedure used to calculate the estimated trend line, and (2) Microsoft's documentation for the Excel Trend Function.

b. As explained above, the marginal cost per customer, column (i), is simply a trend line applied to net distribution plant increase per customer, column (h). The estimated marginal cost per customer was calculated in this manner in order to "smooth" the net distribution plant increase per customer. Because the data for net distribution plant increase per customer, column (h), is "lumpy" (i.e., goes up and down from year to year), it is necessary to smooth the data in order to calculate an estimate of marginal cost. This is a standard approach for estimating marginal distribution plant. Because distribution facilities are often installed as a part of large construction projects, which are initiated both to serve customers that take service immediately and for customers that take service in a subsequent year, annual increases in plant will not correlate directly with additions of new customers during the year.

WITNESS: Steve Seelye

Delta Natural Gas Company, Inc.

Estimate of Marginal Cost with Least Squares Regression

x	y	x^2	xy	est(y) y=mx+b
1	3,227.17	1.00	3,227.17	3,158.00
2	3,476.88	4.00	6,953.75	3,231.11
3	3,569.57	9.00	10,708.70	3,304.23
4	5,934.85	16.00	23,739.41	3,377.35
5	2,769.47	25.00	13,847.36	3,450.46
6	1,757.91	36.00	10,547.44	3,523.58
7	3,796.81	49.00	26,577.67	3,596.70
8	2,356.94	64.00	18,855.53	3,669.81
9	1,315.04	81.00	11,835.35	3,742.93
10	1,795.51	100.00	17,955.13	3,816.04
11	8,759.23	121.00	96,351.53	3,889.16
66	38,759.38	506.00	240,599.04	

m = (n(sum(xy)) - sum(x)sum(y))/(n(sum(x^2))-sum(x)^2)

= (11 * 240599.04 - 66 * 38759.38)/(11 * 506.00 - 66^2)

= 73.12

b = (sum(y)sum(x^2) - sum(x)sum(xy))/(n(sum(x^2))-sum(x)^2)

= (38759.38 * 506.00 - 66 * 240599.04)/(11 * 506.00 - 66^2)

= 3,084.88

TREND

See Also

Returns values along a linear trend. Fits a straight line (using the method of least squares) to the arrays known_y's and known_x's. Returns the y-values along that line for the array of new_x's that you specify.

Syntax

TREND(known_y's,known_x's,new_x's,const)

Known_y's   is the set of y-values you already know in the relationship y = mx + b.

- If the array known_y's is in a single column, then each column of known_x's is interpreted as a separate variable.
- If the array known_y's is in a single row, then each row of known_x's is interpreted as a separate variable.

Known_x's   is an optional set of x-values that you may already know in the relationship y = mx + b.

- The array known_x's can include one or more sets of variables. If only one variable is used, known_y's and known_x's can be ranges of any shape, as long as they have equal dimensions. If more than one variable is used, known_y's must be a vector (that is, a range with a height of one row or a width of one column).
- If known_x's is omitted, it is assumed to be the array {1,2,3,...} that is the same size as known_y's.

New_x's   are new x-values for which you want TREND to return corresponding y-values.

- New_x's must include a column (or row) for each independent variable, just as known_x's does. So, if known_y's is in a single column, known_x's and new_x's must have the same number of columns. If known_y's is in a single row, known_x's and new_x's must have the same number of rows.
- If you omit new_x's, it is assumed to be the same as known_x's.
- If you omit both known_x's and new_x's, they are assumed to be the array {1,2,3,...} that is the same size as known_y's.

Const   is a logical value specifying whether to force the constant b to equal 0.

- If const is TRUE or omitted, b is calculated normally.
- If const is FALSE, b is set equal to 0 (zero), and the m-values are adjusted so that y = mx.

Remarks

- For information about how Microsoft Excel fits a line to data, see LINEST.
- You can use TREND for polynomial curve fitting by regressing against the same variable raised to different powers. For example, suppose column A contains y-values and column B contains x-values. You can enter x^2 in column C, x^3 in column D, and so on, and then regress columns B through D against column A.
- Formulas that return arrays must be entered as array formulas.
- When entering an array constant for an argument such as known_x's, use commas to separate values in the same row and semicolons to separate rows.

Example

Suppose a business wants to purchase a tract of land in July, the start of the next fiscal year. The business collects cost information that covers the most recent 12 months for a typical tract in the desired area. Known_y values are in cells B2:B13; the known_y values are $133,890, $135,000,

$135,790, $137,300, $138,130, $139,100, $139,900, $141,120, $141,890, $143,230, $144,000, $145,290.

When entered as a vertical array in the range C2:C6, the following formula returns the predicted prices for March, April, May, June, and July:

`TREND(B2:B13,,{13;14;15;16;17})` equals {146172;147190;148208;149226;150244}

The company can expect a typical tract of land to cost about $150,244 if it waits until July. The preceding formula uses the default array {1;2;3;4;5;6;7;8;9;10;11;12} for the known_x's argument, corresponding to the 12 months of sales data. The array {13;14;15;16;17} corresponds to the next five months.

Notes

5

5. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 4.

a. (1) Provide all cost-benefit analyses on the installation of electronic reading transmitters ("ERTS") that Delta performed or commissioned.

(2) If no cost-benefit analyses were performed, explain why not.

b. (1) What benefits does Delta receive from ERTS meter installation?

(2) What benefits do Delta customers receive from ERTS meter installation?

c. Provide the number of customers that are currently on ERTS meters.

d. Does Delta plan to install this type of metering for all customers?

e. (1) Describe Delta's current policy on service line installations.

(2) When was this policy implemented?

(3) What effect has this policy had on the embedded cost per customer over the time period in which it has been in effect?

RESPONSE:

a. Delta did not mean to imply in its Response to Item 4 of the June 4, 1999 Commission Data Request that the ERTS were the major reason for increased costs, only that they were one of the reasons. The cost to serve new customers is greater as the embedded costs are at "old" dollars accumulated since 1949 when Delta was started. Inflation and increased construction costs have led to this.

Delta decided to install some ERTS as a trial, to see if they could assist us in reading meters more efficiently. We had looked for alternatives for meter reading automation, considered what others in the industry were doing and decided this might be a viable option.

We acquired 2700 ERTS in May, 1996 and installed them. We decided to systematically acquire more in different fiscal years, so in August, 1996 we acquired 6,000 more ERTS. Then in July, 1997, we acquired 6,000 more, so that our total is now approximately 14,700.

Our approach was to install the ERTS in areas where we could have 100% saturation and obtain the maximum efficiency benefit. We did this in our Stanton, London and part of our Nicholasville system where growth demands were the greatest.

We have not acquired ERTS since 1997, as we are now evaluating and considering them. We believed we had to get enough installed in distinct areas to be able to see their impact. We installed several hundred in each of our other branches so that all branches could utilize them and be familiar with them.

At this point, our analysis indicates that efficiency has improved with the ERTS being installed. Some significant time savings are being realized as indicated, especially considering the customer growth during the last five years:

	1994	1999
Meter reading hours per month	1017	872
Meter reads per hour	40.11	46.07
Company average days required each month to read meters (customer service reps)	3.66	2.66

We plan to continue to review ERTS and consider further use of them in future years, but have no plans at this time.

b.(1) Delta's meter reading is believed to be more accurate, with fewer errors and fewer re-reads. Less time is required and efficiency is improved as described in Delta's Response to Item 6 a. As Delta expands and adds customers, it spreads its work force and overhead over a larger customer base.

b.(2) Delta's customers benefit in future rates by these efficiencies described in 6.b.(1). Also, customer convenience is a benefit as Delta employees may not be required to go on the customer premise, particularly inside fences and interact with customer pets such as dogs. Thus, employee safety is an added benefit.

c. 12,830 residential; 1,570 small commercial; 300 large commercial

d. Not at this time.

e.(1)(2) Delta owns, operates, repairs and replaces service lines. Delta constructs up to 100 feet of new service line at no cost to the customer. This policy was changed in 1989 as a result of proceedings before the Commission in Case NO. 89-041 and the Commission's Order dated 8/17/89 allowing this change. Delta's standard practice was revised to reflect this.

(3) Since 1990, the costs to install and replace service lines has been recorded in Delta's plant account No. 380 – service lines. In Delta's rate case filed July 2, 1999, Item 25 reflects $7,634,652 of gross plant in account 388 at 12/31/98. Accumulated depreciation was $1,213,542 and net book value was thus $6,421,110. This is approximately $169 per customer, which has increased Delta's rate base and imbedded cost. But, Delta's customers have saved the costs of operating, repairing and replacing all service lines as well as the cost of installing new service lines for new customers. This was as contemplated by the Commission in its Order in Case No. 89-041.

WITNESS: John Hall

Notes

6

6. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 11.

   a. Describe the review process that would be available to the Commission.

   b. What time limitations, if any, would be placed on conducting the review under the proposed mechanism?

RESPONSE:

a. & b.

Under the proposed plan, Delta would make an annual filing of the Annual Adjustment Component (AAC) based on budgeted information 30 days prior to the fiscal year beginning July 1 of each year. Because this filing is based on budgeted data and fully reconciled with actual historical costs through the application of the Annual Adjustment Factor (AAF) the following year, we do not envision an extensive review of the AAC filing.

As filed, the AAF would be implemented on October 1 of each year based on the actual results for the fiscal year ended June 30. Since it takes time to close the books for the year and prepare the filing, Delta could have the filing ready for submittal by approximately August 15, which would provide a period of 45 days to review the actual historical costs for the fiscal year.

The Balancing Adjustment Factor (BAF) merely acts as a true-up of volumetric differences in the application of the AAF and prior BAFs. Therefore, no additional cost information will be filed in connection with the BAF. As filed, the BAF would be implemented on January 1 and Delta would submit the filing 30 days prior to that date. Because the BAF is simply a true-up to reflect volumetric differences in application of the AAF and prior BAFs, Delta believes that 30 days should provide adequate time for reviewing this component.

Although we do not want to dismiss the importance of the AAC and BAF, in our opinion it is more important to implement appropriate procedures to evaluate the implementation of the AAF than the other two components of the mechanism. Because the AAF is based on actual historical costs, adjusted for the performance measures, and is used to reconcile the application of the AAC for the fiscal year, the AAF is the more important component. With respect to the procedures for the three components, we recommend the following:

- For the filing of the AAC, the Commission would be allowed to review the budgeted costs for the upcoming fiscal year during the 30 days between Delta's filing and the implementation of the AAC. Any questions concerning the filing could be handled informally through either telephone conversations or an informal technical conference during the 30-day period.

- For the filing of the AAF, the 45-day review period, would allow time for a more extensive review. During this period, the Commission could make inquiries with

Delta by either contacting them by telephone or submitting written inquiries. The Commission could also conduct an informal technical conference to go over the information submitted by Delta in the filing and in response to inquiries. An alternative to this would be to conduct an expedited evidentiary hearing during the 45-day review period. However, we feel that a more effective process would consist of using informal oral and written communications and informal technical conferences if necessary to answer questions raised by the Commission.

- For the filing of the BAF, the 30-day period should allow sufficient time for the Commission to review the reconciliation of the AAF and prior BAFs based on differences between projected and actual billing units used in the application of these components. Although it is unlikely that any substantive issues will arise during the review of the BAF, any inquires could be handled informally.

WITNESS: Steve Seelye

Notes

7. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 13.

a. How much time would the Commission have to conduct the review anticipated by Delta under the proposed mechanism.

b. Mr. Seelye states that the Commission would not have to review pro-forma adjustments in the annual review proceeding. What type of support would Delta supply for the budgeted amounts contained in the Annual Adjustment Component?

c. What financial information should Delta submit to enable the Commission to review Delta's actual historical costs to determine whether these costs were reasonable and whether previously disallowed costs had been excluded from budgeted or historical costs?

RESPONSE:

a. See Delta's Response to Item 6.

b. As specified on Sheet No. 35 of the proposed tariff, Delta would submit its Annual Operating Budget, as approved by the Company's Board of Directors, for the upcoming fiscal year. As explained in Delta's Response to Item 6, Delta would also answer any informal inquires and would be available for a technical conference to review the budgeted cost information.

c. As specified on Sheet No. 35 of the proposed tariff, in conjunction with the AAF filing, Delta would submit a Statement of Actual Income setting forth the calculations of actual net income available for common equity as well as the return on common equity for the fiscal year along with supporting documentation. Delta has no objection to modifying the tariff to provide additional information identified in this proceeding. For example, Delta could provide an account-by-account detail of its costs for the fiscal year. This would provide greater assurance that Delta's costs are reasonable, that previously disallowed costs have been excluded from the historical costs for determination of the AAF and would provide a framework for parties to make further inquires with Delta concerning its costs. As explained in Delta's Response to Item 6, the parties could obtain additional information from Delta in order to satisfy any concerns regarding the appropriate inclusion of certain costs and Delta would be available to answer questions concerning costs during an informal technical conference prior to the implementation of the AAF.

WITNESS: Steve Seelye

Notes

8

8. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 17. What is the source of the "Current Estimated Cost" for competing energy sources other than Kentucky Utilities Company?

RESPONSE:

The price information on fuel oil was obtained from a supplier in Mt. Sterling, Ky; the information on coal was obtained from information provided by a coal supplier in Middlesboro, Ky.; and the information on propane was obtained from information provided by Delta's customers that regularly purchase propane.

WITNESS: Steve Seelye

Notes

9

9. Explain why the provisions of the Alabama gas Corporation's Rate Stabalization and Equalization Plan relating to monitoring were not included in Delta's proposal.

RESPONSE:

We anticipated that provisions governing monitoring would be developed in the current proceeding. As pointed out in our response to Item 6, we believe the Commission has available to it the authority to adequately monitor the utility's costs and to conduct an investigation of particular cost items even after implementation of the AAF. This could be done either as a part of annual or 3-year reviews.

In addition, it was never our intention to model Delta's Alternative Regulation Plan directly off of Alabama Gas Corporation's RSE. In several key respects, we feel that we have improved upon the mechanism (eg., the use of the AAF to fully reconcile actual historical costs subject to performance measures.) Delta thought it would be presumptuous to include some of the language set forth in the RSE. For example, item 1 of the Special Rules Governing the Operation of RSE states as follows:

> The Commission finds that the adoption of RSE and the resulting reduction of the number of general rate increase requests filed by the Company, given the increased monitoring and auditing provisions of the RSE and this agreement, will increase the Commission's ability to fulfill its statutory duty to supervise the overall operation of the Company as provided in Title 37, Code of Alabama (1975). The absence of lengthy and time-consuming hearings occasioned by general rate cases brought by this Utility will provide a better opportunity for the Commission and its staff to effectively monitor the Company's daily operations and to investigate regulatory matter which heretofore have remained unaddressed.

Although we are in general agreement with this pronouncement, we felt that it would be too presumptuous to include language such as this in Delta's tariff. Alabama Gas Corporation's RSE was the result of extensive litigation and much of the tariff language seems to reflect this fact. In submitting its proposal, Delta was confident that mutually agreeable provisions for monitoring could be worked out.

WITNESS: Steve Seelye

Notes

10

10. In its Response to the Commission's Order of June 4, 1999, Item 32, Delta failed to discuss differences between its proposed mechanism and the Alabama Gas Corporation's Rate Stabilization and Equalization Plan relating to the provision of the company's financial information to the regulatory commission and to audits and inspections by the regulatory commission.

a. (1) Why does Delta's proposed mechanism not require Delta to fill all of the documents that are set forth in Alabama Gas Corporation's Second Revised Sheet No. 51 ("Exhibit A – Special Rules Governing Operation of RSE")?

(2) Should the Commission condition the establishment of any alternative rate mechanism upon Delta's provision of the documents listed in Alabama Gas Corporation's Second Revised Sheet No. 51 and upon the same reporting requirements?

b. Why does Delta's proposed mechanism not provide for periodic auditing and inspection by the Commission as Alabama Gas Corporation's Rate Stabilization and Equalization Plan does?

RESPONSE:

a. (1) We anticipated that appropriate filing requirements in addition to those set forth on Sheet No. 35 of Delta's proposed tariff could be developed, if necessary, in the current proceeding.

(2) Delta routinely submits copies of its financial and operating reports to the Commission. However, if these or other documents are required as a part of filings under the Alternative Regulation Plan, then Delta does not object to providing these documents.

b. We believe that the Commission has the authority to conduct periodic audits and inspection of the Alternative Regulation Plan. The Commission has frequently conducted audits of the application of gas supply clauses and fuel adjustment clauses even though we are unaware of provisions set forth in the utilities' tariffs that provide for such audits. Delta thus saw no need to provide for such auditing and inspection.

WITNESS: Steve Seelye

Notes

11. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 20.

a. Describe in detail each type of audit performed by the Alabama Public Service Commission in connection with Alabama Gas Corporation's Rate Stabilization and Equalization Plan.

b. (1) Does the staff of the Alabama Public Service Commission perform periodic audits of Alabama Gas Corporation's financial records to monitor Alabama Gas Corporation's RSE Plan?

(2) If yes, do such periodic audits enhance the program by providing greater assurance that the rates resulting from the plan are fair, just and reasonable?

c. Should the Commission condition the establishment of any alternative rate mechanism upon periodic audits of Delta's financial records by Commission Staff or an independent auditor. Explain.

RESPONSE:

In developing our response to items (a) and (b), we contacted the Alabama Public Service Commission staff member responsible for supervising the review of the application of the RSE. After writing the response to items (a) and (b), we called the staff member back and read the response to him in order to ensure that it was accurate and complete. He agreed that it was.

a. According to the representative that we spoke to at the Alabama Public Service Commission, the Commission Staff conducts a General Compliance Audit every 3-5 years. As a part of this audit, the Commission Staff reviews the application of Alabama Gas Corporation's rate schedules, including the RSE. In this audit they also review the application of billing systems, accounting and financial records, and rate compliance. The General Compliance Audit is generally a 5-6 week process. Upon completion of the audit, the Staff submits a report to the Commission describing the findings of the audit.

b. (1) According to information we obtained from the Alabama Public Service Commission, the staff performs periodic audits of Alabama Gas Corporation's financial records to monitor Alabama Gas Corporation's RSE Plan. This is performed as a part of the General Compliance Audit performed every 3-5 years. The Staff also conducts 2-3 day "spot audits" regarding issues ("things that catch their eye") that may arise as a part of their ongoing review of the RSE.

(2) The Alabama staff believes that such periodic audits enhance the program by providing greater assurance that the rates resulting from the plan are fair, just and reasonable. The representative that we spoke to also indicated that Alabama Gas Corporation is operating within the letter and the spirit of the RSE and that the RSE program does ensure that its rates are fair, just and reasonable. A key element to this was the introduction of the operation and maintenance expense cap several years back. The

representative we spoke to also indicated that the RSE gave the Commission greater access to the utility's records than they had prior to the implementation of the mechanism.

c. Delta sees no need for a provision requiring such audits of Delta's financial records by the Commission. If the Commission feels that is advisable and necessary it can always undertake those as it so determines.

WITNESS: Steve Seelye

Notes

12. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 20. As part of its RSE Plan, Alabama Gas Corporation agreed to the use of the Uniform System of Accounts ("UsoA") for the RSE and agreed to bear the burden of proof as to the amount and verification of expenditures and conformity with the UsoA in any limited complaint proceeding on computation of the RSE.

a. Why did Delta exclude these provision from its proposed tariff?

b. Should the Commission condition the establishment of any alternative rate mechanism upon inclusion of such provisions?

RESPONSE:

a. We did not see that this was necessary. We anticipated that any appropriate requirements could be developed, if needed, in the current proceeding.

b. Delta does not believe such provisions are necessary or required.

WITNESS: Steve Seelye

13. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 21. As Delta's proposal assumes a thorough and accurate budgeting process, additional information regarding this process is necessary.

a. If no written procedures, guidelines, internal standards, rules, policies and regulations regarding the preparation of Delta's budget exist, provide a thorough description of the process. This description shall address, at a minimum, reporting centers (responsible to officers), source documents and analyses used in Delta's budget preparation process and pertinent factors used to develop Delta's budget.

b. Should Delta's budgetary guidelines and process not be documented in writing since its budget is the proposed starting point for any adjustment under the proposed alternative rate mechanism? Explain.

RESPONSE:

a. and b. Delta has a thorough and accurate budgeting process. As Delta is a relatively small, informal company with a fairly simple, flat organization, it is not necessary to reduce everything to written documentation. Delta's budget process starts with the President & CEO and is controlled by the officers for their areas of responsibility. Delta's officer team normally meets weekly and budget preparation is discussed in those meetings as required. All officers are assigned budget areas of responsibility, so that all revenue, expenses and capital accounts of the Company are assigned to one of the officers. They are responsible for developing the budget for each account, by month, and for monitoring actual results for each of those accounts.

Delta believes it has a thorough and accurate budgeting process. Budgets are meant to be financial guidelines. Actual results reflect what actually happens and can vary from budgeted plans. The key is to manage the company and the variances effectively.

There is communication with all budget agents (officers) at the start of the budget process, providing information by the Controller's office as to actual results versus budget for previous periods and provides for analyses or detail for particular budget accounts as required. (See attached letter dated 2/1/99 relating to fiscal 2000 budget process). Major assumptions are provided by the officers (such as pay increase percentages, normal weather). Any employee changes and all pay changes are reviewed and approved by the President & CEO. All officer compensation is approved by Delta's Board, as well as the overall payroll increases provided for all employees. Budget agents consider trends, inflation, known changes, demands for the next year in all their areas and accounts, and any input from management in their areas or other areas if interrelated.

The officers involve their various departments and analyze and review all accounts for which they are responsible. After all input from department heads, budget requests, by account, are prepared. These are reviewed by the officers and adjusted as necessary. Final review by the officers and the President & CEO provides any final adjustments prior to finalizing the proposed budget for submission to Delta's Board of Directors.

Delta's Board reviews the detail budget, by account, comparing the proposed budget to the previous budget and to the recent twelve months. One benefit of a smaller, tightly organized Company such as Delta is the close, quick communication such as is done for the budget process. The officers simply get together, discuss budget preparation details and then do it.

Since Delta is fairly small and informal, with direct hands on management and involvement for the officers of the Company on a continuous basis, no further written guidelines are considered necessary.

WITNESS:
John Hall

Date: February 1, 1999

To: Glenn, Alan (with detail budget worksheet attachments to Mary V.), John, Bob and Johnny (with detail budget worksheet attachments to Donna F.)

CC: Marian, Kathy, Donna S., Mary V., Donna F.

From: John B

Subject: Budgets - Fiscal 1999-2000

Attached are the system reports designed to help you develop your budgets for the period July 1, 1999 to June 30, 2000. These reports reflect how the system is currently set up. Please let me know if you see corrections that need to be made in account assignment, or if there are new accounts needing to be added:

- **Chart of Expense Accounts and Budget Agent Responsibility Report** A listing of expense account assignments in account number order. (Impromptu BAS120A)
- **Chart of Capital Accounts and Budget Agent Responsibility Report** A listing of capital account assignments in account number order. (Impromptu BAS120B)
- **Budget Account Worksheets** You should receive a separate page for each budget account in your responsibility area. These worksheets show Budgeted and Actual Amounts by month for fiscal 1998, Budgeted and Actual Amounts by month for calendar 1998, and Budgeted amounts by month for fiscal 1999. A column is also included for writing in your proposed 2000 budget. (Income stmt a/c's: Impromptu & Transformer BAS120, Powerplay 120t1; Capital a/c's: AS400 Query CAPBUDGET/JOHNB, Impromptu & Transformer BAS120CP; Powerplay 120cp01)

As a review, the best way to research the history of your budget accounts is as follows:

P&L accounts:

Use the "G/L History Search" option on your AS400 menu. Choose an option 1 "G/L Search" and option D "Detail". Enter the account # in question (or use F4 key and pick from the list). This screen will show you all charges hitting this account and the source. If the source is accounts payable, you can enter a 1 on the row, and drill down into accounts payable to see the vendor paid.

Capital accounts:

By Budget Code – If you are just interested in the charges made to the budget code, you can use the "Budget Search" option on your AS400 menu. Enter a 1 to select the capital budgets, then enter your agent and budget codes. The charges to that budget code will appear. You can enter a 1 in front of any accounts payable charge to drill down to get vendor name, etc.

By Budget Code AND Work Order Number – If you are interested in knowing which work order the budget dollars have been coded to, you will need to review the history on the "Capital Expenditure by Budget and Work Order Report" as described in my memo dated 1/14/99. Kathy has included a copy of this report for the fiscal year ended 12/31/98 in the December budget packages. If you would like to have this for a different period of time, let she or I know, and we will run it for you.

Budget requests need to be submitted to me by **March 15, 1999**. As in the past, you can opt to submit the completed budget worksheets to me or input them directly into the system by the due date.

All budgets should be prepared the same way as in past years based upon the months you think the expenditures will occur. If you know of no specific monthly requirements, spread the estimates to each month equally. Capital should be budgeted for total completed, installed costs, which should include material, contractors, company labor, overheads and other.

Please contact me if you have any questions or if I can be of any other help.

14. (a) Did Delta consider proposing the establishment of a weather normalization adjustment ("WNA") to stabilize earnings?

(b) If not, why not?

RESPONSE:

(a) Delta did not consider the establishment of a weather normalization adjustment as a part of the proposed Experimental Alternative Regulation Plan. However, Delta has filed for a weather normalization plan in connection with the rate case that was filed on July 2, 1999 (Case No. 99-176).

(b) The proposed Alt Reg Plan is designed to take into account the impact of weather and other factors that work to destabilize the Company's earnings. The proposed plan can function either without or in consort with a weather normalization adjustment. The end result should be the same.

WITNESS: Randall Walker

15. Would the establishment of a WNA in combination with the ability to file a future test year rate proceeding accomplish some measure of the rate and earnings stabilization contemplated in Delta's alternative regulation filing? Explain.

RESPONSE:

A weather normalization adjustment, if designed properly, can provide some measure of rate and earnings stabilization. We assume that, in this instance, the word "rate" means monthly Company revenues and/or customer billings, not the unit charges themselves. Earnings would only be stabilized to the extent of the variations that were solely related to departures from normal temperatures. The degree to which a future test-year rate proceeding would accomplish rate and earnings stabilization is less quantifiable and more speculative. If we understand the future test-year correctly, the rates that are placed into effect pursuant to such a filing are not implemented concurrent with nor are they applied in the same 12-month period that was used to determine the revenue requirements. If this is the case, there remains, even with the future test-year process, some disconnect between the actual and the sought after results.

While both of the above in combination will accomplish some measure of rate and earnings stabilization, we believe that the proposed Alt Reg Plan will address all factors that work to de-stabilize earnings. Furthermore, the Actual and Balancing Adjustment Factors contained in the proposed Alt Reg Plan will work to safeguard the proper relationship between actual and intended results.

WITNESS: Randall Walker

Notes

1. Please provide the following data for the twelve months ended June 30, 1999.

   a. Update the response to AG-8 with monthly statements through June 30, 1999.

   b. Provide the actual NIAC for the fiscal year ended June 30, 1999.

   c. Provide the actual 12-month average Common Equity (exclusive of non-regulated subs and Canada Mountain) for the fiscal year ended June 30, 1999.

   d. Extend the responses to AG-33 and AG-35 to include actual data through June 30, 1999.

RESPONSE:

This information will be provided when it is available. Delta's auditors are expected to sign off for the fiscal year ended June 30, 1999 by August 13, 1999.

WITNESS:

John Hall

2. With regard to the response to Ag-11, provide the following additional information:

a. Translate the actual dollar amount rate increase for each of the 5 base rate cases from 1982 through 1997 shown in the middle column into overall composite percentage (%) rate increases.

b. Based on the rate increases listed in the middle column that occurred during the 15-year period of approximately December 1982 to December 1997, what would these rate increases translate into (1) in terms of an average annual dollar amount rate increase for each year in this 15-year period, and (2) in terms of an average annual % rate increase for each year in this 15-year period.

c. What were the actual rate case expenses associated with rate cases (3), (4), and (5)?

RESPONSE:

a.

Actual Increase	% Increase
$ 1,670,000	4.28
116,000	.3
2,050,000	7.0
683,000	2.26
1,370,000	4.5
1,306,000	Data not available

b. The total amount of the five rate increases was $7,195,000. If the $7,195,000 is divided by 15 years, the average would be approximately $479,000.

The individual amounts that make up this total were based on the test period volumes from each respective rate case. Therefore, inasmuch as the volumes as well as the make up of deliveries between the rate classes change each year, neither the average dollar amount nor the average percentage increase applicable to the actual customer billings can be calculated with any degree of precision.

c. (3) 65,223 (out of pocket only)
(4) 58,820 (out of pocket only)
(5) Data not available

WITNESS:

John Hall

Notes

3. With regard to the response to AG-20, provide the following information:

(a) What would the "5% limitation rate increase" be for each of the fiscal years on Schedule A based on annual revenues from prior years exclusive of GCR revenues(i.e. only based on prior year non-GCR base rate revenues)?

(b) If the Company's AAC non-gas base rate increase for any particular year is limited to 5% of the total operating revenues for the prior year (which revenues would include GCR revenues) -- as proposed by the Company as part of the ARP -- but for this same year the Company will also receive, let's say, a 3% increase in its GCR rates through the GCR mechanism, doesn't this mean that the ratepayer for this particular year will experience an 8% increase in its overall rates? If this is not correct, explain in detail why not.

RESPONSE:

(a)	Schedule A Page 1 1995-96	Schedule A Page 2 1996-97	Schedule A Page 3 1997-98
Annual Revenues from Prior 12-mo. Period -	$27,912,362	$30,711,266	$36,116,328
Less: GCR Revenues	$11,687,405	$12,792,501	$19,103,276
Revenues excl. GCR	$16,224,957	$17,918,765	$17,013,052
5% of above	$811,248	$895,938	$850,653

(b) The statement would be correct if the underlying assumption contained in the AG's question relating to the GCR increase was modified to state that the GCR increase represented a 3% increase in overall rates rather than an increase of 3% in GCR rates. However, it should be pointed out that if the GCR reduced overall rates by 3%, the ratepayer would only experience a 2% increase. The GCR does go both up and down, and it adjusts quarterly.

WITNESS: part a - Randall Walker
part b - Steve Seelye

Notes

4. With regard to page 3 of the ANALYSIS of Proposed Alternative Ratemaking Methodology, as well as the supporting workpapers in response to AG-31, please provide the following information:

(a) The Common Equity (Utility) balances shown for each month in the second column exclude equity associated with the Company's unregulated subsidiaries, and also excludes 36.25% (assumed allocated equity portion) of the monthly investment in the Canada Mountain project. Please confirm this. If you do not agree, explain your disagreement in detail.

(b) A portion of the Company's per books interest expenses represents interest associated with the debt allocated to the Canada Mountain project at an assumed capital structure ratio of 63.75% (= 100% less equity allocation of 36.25%). Please confirm this. If you do not agree, explain your disagreement in detail.

(c) The supporting workpapers in response to AG-31 show that the Company deducted 100% of its per books interest (i.e. including interest expenses allocable to the Canada Mountain project) in calculating the NIAC (utility) in the third column of page 3 of the ANALYSIS of Proposed Alternative Ratemaking Methodology. If you do not agree, explain your disagreement in detail.

(d) In order to arrive at the proper NIAC (Utility) numbers in the third column of page 3, the Company should only have recognized the non-Canada Mountain allocable interest expense as the appropriate interest expense deduction. Please confirm this. If you do not agree, explain your disagreement in detail.

(e) Please provide the actual NIAC (Utility) numbers in the 3rd column of page 3 after correcting for the allocated Canada Mountain related interest expense overstatements described in parts c and d above?

RESPONSE:

(a.) Yes.

(b.) Yes.

(c.) It is true that the interest allocable to Canada Mountain is included in the interest expense that was deducted in determining the NIAC shown on page 3 of the ANALYSIS of Proposed Alternative Ratemaking Methodology. However, the way that NIAC is calculated, Canada Mountain interest is eliminated from the determination of the NIAC. Since operating revenues on the financial statements included the recovery of the interest expense associated with Canada Mountain and the purchased gas costs did not, it was necessary to leave the Canada Mountain interest in interest expenses in the determination of NIAC. To do otherwise would have overstated the NIAC. In our illustrative examples, we could have made an upward adjustment to purchased gas expenses reflecting the Canada Mountain interest and a corresponding downward adjustment to interest expenses. However, the NIAC would have been remained the same. Therefore, we elected to handle the Canada Mountain interest expenses in a simplified manner rather than over complicating the illustrative examples.

(d.) See response to part (c).

(e.) See response to part (c).

WITNESS: Randall Walker

Notes

5. Please provide the workpapers, calculations and calculation components supporting the actual 1996, 1997 and 1998 ROE numbers of 10.2%, 6.1% and 8.6% stated in the response to AG-36 (b).

RESPONSE:

The ROE numbers in response to AG-36 (b) were calculated by adding together the Net Income Available for Common shown in column 3, page 3 of the ANALYSIS of Proposed Alternative Ratemaking Methodology for each 12-month period and dividing by the Common Equity at June of each year (column 2).

	Net Income Available For Common 12-Months Ended	Common Equity @ June	ROE
June 1996	$2,066,998	$20,256,334	10.2%
June 1997	$1,407,939	$23,162,194	6.1%
June 1998	$2,025,723	$23,435,387	8.6%

WITNESS: Randall Walker

Notes

6

6. Please reconcile the average number of customers shown in the responses to AG-59, AG-67 and PSC-3 for the corresponding periods.

RESPONSE:

AG-59 schedule reflects the average number of customers based on calendar year. AG-67 schedule reflects the average number of customers based on fiscal year. PSC-3 schedule reflects the actual number of customers as of the end of June for each fiscal year.

WITNESS: John F. Hall

Notes

7. In the response to AG-103 and AG-104, the Company claims that the operation of the GCR has not in any way impacted the proposed ARP and is totally removed from the Company's proposed ARP.

(a) Isn't it true that in calculating the "5% base rate increase limitation" this rate increase limit is determined by applying 5% to the Company's overall revenues for the prior year and that such revenues include the Company's GCR revenues?

(b) Doesn't it therefore follow that the GCR revenues to a large extent influence and determine the "5% base rate increase limitation" in the Company's proposed ARP?

RESPONSE:

(a) Yes. The limitation is based on a percentage of overall revenues.

(b) This is correct as far as establishing the 5% limitation is concerned. However, because the proposed mechanism provides for a true-up or reconciliation through the Actual and Balancing Adjustment components there is ultimately no impact on the ARP from the operation of the GCR.

WITNESS: Steve Seelye

Notes

8

8. How does the Company propose to treat all of the costs associated with all of the annual and 3-year review procedures and activities listed and described in the responses to PSC-8 and PSC-13? Will they be estimated in the budget for each proposed AAC year and will all of the actual expenditures be included in the calculation of the AAF? Please be specific in your response.

RESPONSE:

It is not anticipated that any incremental costs will be budgeted for the annual and 3-year reviews. We are hopeful that Delta will be able to use its existing internal resources to participate in these reviews, as well as audits, additional filing requirements, etc. that might be specified in this proceeding. However, to the extent that incremental costs are incurred in conjunction with these reviews, such Commission allowable costs (e.g. for legal and consulting services) would be recorded in the appropriate accounts and included in the determination of the AAF.

WITNESS: Steve Seelye

Notes

9

9. With regard to the response to PSC-15, has Delta historically filed rate cases on an annual basis? In this regard, please provide the filing dates of Delta's general base rate cases during the last 15 years.

RESPONSE:

Delta has not historically filed rate cases on an annual basis. See the response to AG's data request No. 11 dated June 4, 1999 for filing dates of Delta's general base rate cases for the last 15 years.

WITNESS:

John Hall

Notes

10. With regard to the response to PSC-33 (e), the Company states that its proposed ARP would not provide for full recovery of revenue requirements, whereas LG&E's gas supply clause provides for full cost recovery. LG&E's PBR mechanism all involve costs that flow through its GSC and the Company will incur penalties (disallowance of cost recoveries in its GSC) if it doesn't meet certain standards and benchmarks regarding certain gas supply costs. Please explain why the Company can claim that LG&E's gas supply clause, as currently in effect, guaranteed full cost recovery?

RESPONSE:

We agree that in conjunction with the PBR, LG&E's GSC does not provide for full cost recovery. Our statement was referring to the GSC as a stand alone mechanism without the PBR acting as an adjunct to the GSC mechanism. In our effort to describe the similarities and differences between LG&E's GSC/PBR mechanism and Delta's proposed Alternative Regulation Plan, we were obviously not as clear as we would have liked. What we were trying to say is that the LG&E's GSC (without the application of the PBR) is very similar to Delta's Alternative Regulation Plan (without the application of the performance measures), except that LG&E's GSC (without the application of the PBR) provides for full cost recovery, whereas Delta's Alternative Regulation Plan (without the application of the performance measures) operates within a band around the rate of return. Therefore, in this limited respect, without considering either LG&E's PBR or Delta's proposed performance measures, LG&E's GCR provides for full cost recovery, whereas Delta proposed Alternative Regulation Plan does not inasmuch as Delta's mechanism operates within a rate of return range. Once LG&E's GCR is considered in the context of the PBR, and Delta's Alternative Regulation Plan is considered in the context of the rate of return range and the proposed performance measures, neither LG&E's GSC/PBR nor Delta's Alternative Regulation Plan provides for full cost recovery.

WITNESS: Steve Seelye

Notes

11

11. Is it true that, over and above the non-gas cost related ARP proposed by Delta, the Company will continue to receive full dollar-for-dollar recovery of its actual gas costs (making up approximately 60% of its total operating costs – see response to AG-19) through its GCR? If you do not agree, explain in detail.

RESPONSE:

Yes.

WITNESS: Steve Seelye

Notes

12. The response to PSC-20 includes, among other things, a copy of the RSE of Alabama Gas Company. In this regard, please provide the following information.

(a) As shown on the Fourth Revised Sheet No.45, isn't it true that this RSE allows for three"AAF" type true-ups (performed quarterly *ex post*) but these true-ups are not symmetrical, i.e., a true up will only be implemented if it involves a required rate decrease, but will not be implemented if it involves a rate increase? If you do not agree, explain in detail.

(b) As described on Fourth Revised Sheet No. 45, point 3), the O&M/customer index for, let's say, year 2 of this RSE is based on the actual O&M/customer during year 1 of this RSE, multiplied by the annual CPI-U increase. If you do not agree, please explain in detail.

(c) As described on Fourth Revised Sheet No. 45, point 4), isn't it true that if Alabama Gas Company's actual O&M expenses during any particular year are in excess of the CPI-U adjusted O&M expenses, plus 1.25%, then it is only allowed to recover 25% of this cost excess? If you do not agree, please explain in detail.

(d) The response to AG-59 shows the "Recoverable O&M expenses/customer" under Delta's proposed ARP would have been as follows for the following years:

1994	$248.80
1995	$242.55
1996	$252.89
1997	$251.00
1998	$251.75

Based on the O&M Index provisions stated on the Fourth Revised Sheet No.45. points 2), 3) and 4) of the Alabama Gas RSE, the comparable "Recoverable O&M expenses/customer" for Delta would have been as follows for the same years

1994	$247.69
1995	$243.16
1996	$245.91
1997	$243.47
1998	$237.14

If you do not agree with the above-stated "Recoverable O&M expenses/customer" data, explain your disagreement and show what the comparable "Recoverable O&M expenses/customer" for Delta would have been under the Alabama Gas RSE in accordance with your calculations. Provide all supporting calculations and assumptions.

12. (continued)

RESPONSE:

(a) The three "true-ups" provided for in the Alabama Plan appear to be quite different than the AAF "true-up" proposed by Delta. The three "true-ups" in the Alabama Plan never seem to fully reconcile the recoveries thereunder with actual results, whereas the AAF and BAF in Delta'a proposal do provide for full reconciliation. Therefore, while we agree that the Alabama Plan does only provide for downward adjustments to rates pursuant to the "true-ups", we must point out that the resulting impact of these true-ups cannot be compared to Delta's AAF. Because of the inclusion of the AAF and BAF components in Delta's proposal, we believe that Delta'a Plan provides for greater assurance that the rates reflect the cost of providing service.
(b) Point 3 of Fourth Revised Sheet No. 46, does provide for this.
(c) Point 4 of Fourth Revised Sheet No. 46, does provide for this.
(d) In our response to AG-59, we merely performed calculations and analysis based on the parameters prescribed by the AG in its information requested. The Company made no claim that the resulting expenses/customer calculated in that analysis represented, in any way, "recoverable" amounts. The Company's proposal provides that the indexed O&M expenses be determined from a base O&M expense approved by the Commission in the Company's most recent rate case. We see no such provision in the Alabama Plan. Therefore, we can see no meaningful relationship between the two numbers with respect to what would ultimately be passed through to the customers.

WITNESS: Randall Walker

Notes

13

13. Please refer to Delta's response to question 49 of the Attorney General's data request dated June 4, 1999. The response refers to the Notes to Consolidated Financial Statements in Delta's 1998 Annual Report. Notes 6 & 7 on pages 19 and 20 of the 1998 Annual Report describe a 7.15% $25,000,000 debenture series, a 8.3% $15,000,000 debenture series, a 6 5/8% $15,000,000 debenture series and a non-interest promissory note in the amount of $1,800,000 issued on 1995. For each of these series and any other series of debt outstanding provide the following:

a. The amount of original issue.
b. The amount outstanding of each issue at the end of the test year for this case.
c. The amount of issuing expenses associated with each issue.
d. The amount of discount or premium associated with each issue.
e. The amount of unamortized issuing expense, discount or premium associated with each issue as of the end of the test year for this case.
f. The interest payment date or dates, if semi-annual, each year.
g. The specific maturity date for each issue.

RESPONSE:

a. See Note 6 on page 19 and 20 of Delta's 1998 Annual Report.

b. See Consolidated Statements of Capitalization on Page 15 of Delta's 1998 Annual Report.

c.

$25,000,000 of 7.15% Debenture	$1,202,205
$15,000,000 of 8.3% Debenture	689,666
$15,000,000 of 6 5/8% Debenture	753,063
$ 1,800,000 Non-Interest Promissory Note	-0-

d. Zero.

e.

$25,000,000 of 7.15% Debenture	$1,514,853
$15,000,000 of 8.3% Debenture	640,300
$15,000,000 of 6 5/8% Debenture	1,575,600

f.

$25,000,000 of 7.15% Debenture	Due April 1 and October 1
$15,000,000 of 8.3% Debenture	Due February 1 and August 1
$15,000,000 of 6 5/8% Debenture	Due April 1 and October 1

f. See Note 6 on page 19 and 20 of Delta's 1998 Annual Report.

WITNESS: John F. Hall

Notes

14

14. Reference response to AG Request No. 63. Further explain what procedural mechanism would result in the "Order of the Commission." Would there be a general rate case? A hearing on a complaint? An investigation resulting from a Commission-ordered proceeding? Other? Explain.

RESPONSE:

We have assumed that a lawful Commission Order changing the rate of return range pursuant to a Commission proceeding that was initiated for whatever reason would require the Company to change, on a prospective basis, the rate of return range utilized for purposes of the ARP calculations. We would envision that such an investigation would most likely result from a Commission-ordered proceeding. However, nothing would preclude Delta from filing a general rate case or any other party filing a complaint.

WITNESS: Steve Seelye

Notes

15. Reference response to AG Request No. 64. Would your answer be the same if traditional regulation process were commenced by a Commission order issued as a result of the Commission's own action or by a third-party's (non-Delta/Non-PSC) actions? If no, please explain Delta's understanding when, as requested in AG No. 64, rates would be changed.

RESPONSE:

Yes.

WITNESS: Steve Seelye

Notes

16. Reference response to AG Request No. 64h. Please provide:

(a) Specific Reference to each rate schedule section describing the requested procedures applicable to a 3-year review; and
(b) The gas supply cost recovery mechanism with each section describing the "similar" procedures highlighted for the reader.

RESPONSE:

We do not understand the question as it relates to either the AG's Request No. 64 or the Company's response.

WITNESS: Steve Seelye

Notes

17. Reference response to AG Request No. 73.

(a) If a budget amount is later (in the 3-year review) determined to have been unreasonably included in Delta's budget, is that expense refundable? Or is that expense to be considered non-includable in future budgets for ARMAC purposes? Other? Explain.

(b) If a budget item amount is later (in the 3-year review) determined to have been imprudently included in Delta's budget, is that expense refundable?

RESPONSE:

(a) If in a 3-year review, the Commission finds that the Company actually recovered an expense item that it should not have under the Alt Reg Plan, we assume that the amount of such expense actually flowed through to the customers would be refunded. This is no different from what could happen with respect to the application of a fuel adjustment clause, demand-side management cost recovery mechanism, gas supply clause, or environmental cost recovery mechanism. We assume, however, that the 3-year review will be more concerned with the actual expenses that have been recovered after the application of all three components of the mechanism (the AAC, AAF and BAF).

(b) We have assumed that it would be refundable if the "imprudently included" amount ended up being passed through to the customers after application of all three components of the mechanism (the AAC, AAF and BAF). However, we would anticipate that the annual reviews and procedures established in this proceeding will prevent this from happening.

WITNESS: Steve Seelye

18.	Reference response to AG Request No. 74. Please provide, not references to where Delta believes its proposed filing requirements and rules of procedure can be found, but provide an actual statement of each and every one of Delta's proposed filing requirements and rules of procedure that it is recommending or believes the Commission should adopt in the current proceeding.

RESPONSE:

Prior to responding to this request, we would like to point out that because this is an alternative regulation plan and not a general rate case filing the proposed procedural schedule would contemplate a more informal approach to implementing changes in rates. We feel that an informal approach is more conducive to collaboration, easier to implement and more consistent with the concept of alternative regulation. In spite of the fact that the procedures for Delta's Alternative Regulation Plan are more informal than a general rate case, nothing in these procedures is intended to prevent the Commission from asking questions and obtaining data necessary for their review.

Delta's proposed filing requirements and procedures are outlined below:

Annual AAC Filing

On or before June 1 of each year Delta will file revisions to its AAC for implementation on July 1 of the same year, which corresponds to the beginning of Delta's fiscal year. As a part of the filing, Delta will submit its Annual Operating Budget, as approved by the Company's Board of Directors. Delta will also submit a statement detailing the monthly budgeted net revenues (exclusive of gas supply costs) and MCF sales of each rate class billing block for all applicable rate schedules. Delta will also submit a statement detailing a monthly forecast of net revenues, by rate class billing block, for an additional three months beyond the budget year along with a monthly forecast of Mcf sales and transportation volumes, by rate class billing block, for an additional six months beyond the budget year. Delta will also submit a statement of Budgeted Income setting forth the calculations of expected net income available for common equity as well as the return on common equity for the budget year, along with supporting documentation.

Within the thirty day period between the filing of AAC and the implementation of AAC, the Commission Staff can contact Delta either by telephone or in writing to request additional information. Delta or the Commission Staff can also request an informal technical conference during the thirty day period to discuss Delta's filing as well as any supporting documentation. The Commission will then issue an Order implementing the AAC.

The short time frame for conducting the review is necessitated by the fact that Delta's budget is approved in May by its Board of Directors and its fiscal year begins on July 1. However, in our opinion, it is more important to conduct a more thorough review of the AAF than the other two components of the mechanism. Because the AAF is based on actual historical costs, adjusted for the performance measures, and is used to reconcile the application of the AAC for the fiscal year, the AAF is the more important component. (See Delta's response to Item 6 of the Commission's Order dated July 2, 1999.)

Annual AAF Filing

On or before August 15 of the second year and each year thereafter, Delta will file revisions to its AAF for implementation on October 1. As a part of the filing, Delta will submit a statement showing the actual net revenues and Mcf sales for the most recent fiscal year. Delta will also submit a statement of Actual Income setting forth the calculations of actual net income available for common equity as well as the return on common equity along with the supporting documentation.

Within the 45-day period between the filing of AAF and the implementation of AAF ("review period"), the Commission Staff can contact Delta either by telephone or in writing to request additional information. It is anticipated that there will be an informal technical conference to discuss the filing. The Commission would then issue an Order in the proceeding.

Annual BAF Filing

On or before December 1 of the second year, and each year thereafter, Delta will file revisions to its BAF for implementation on January 1. As a part of this filing, Delta will submit a statement showing a reconciliation of amounts that should have been recovered or refunded under the AAF and previous BAFs and amounts actually recovered or refunded under these components as well as a calculation of the upcoming BAF. Although the Commission staff would not be precluded from asking Delta to provide additional information or from requesting a technical conference, it is not anticipated that such actions will be taken with respect to this filing. The Commission would then issue an Order implementing the BAF.

WITNESS: Steve Seelye

Notes

19

19. Reference response to AG Request No. 79. Please provide the basis of Mr. Hall's testimony at page 3, line6.

RESPONSE:

Please see Delta's response to items 13, 18, 30, and 34 of the Commission's Order of June 4, 1999. See also pages 3-6 of the letter to the Commission from John Hall dated February 5, 1999 (included as Exhibit 1 of the pre-filed direct testimony of William Steven Seelye.)

WITNESS: John Hall

Notes

20. Reference response to AG Request No. 79. For the Schedule A fiscal years ending June 1996, 1997 and 1998, please provide

(a) Monthly budgeted residential customer additions;
(b) Monthly budgeted construction expenditures related to budgeted residential customer additions;
(c) Monthly non-gas expenses related to budgeted residential customer additions;
(d) If requests to a, b, and c above cannot be provided, please explain why not;
(e) Please explain how expected number of customers are "taken into account" in preparing the capital budget; and
(f) Please explain how expected number of new customers "impacts" budgeted non-gas supply expenses.

RESPONSE:

(a) The Company's budget is based on an estimate of an average number of customers expected to be served during the budget period (see Response to Item 7 of the Commission Data Request dated June 4, 1999). Customer additions are not budgeted monthly.
(b) See Delta's Response to Item 20(a). The Company's expected construction expenditures in its budget are not forecasted on a customer-specific basis. When mains are installed in a new development, some of the homes may be built and connected immediately while others may take awhile. As a result, budgeted capital expenditures can not be directly tied to the forecasted customer additions within a specific budget period. The Company does take into consideration the expected incremental growth rate as related to the growth rates in previous years when preparing its estimate of expected capital expenditures for the budget period. It also considers trends in its service area and planned construction it is aware of as well as the Company's extension and service line policies.
(c) As with the budgeted capital expenditures, the Company's expected non-gas expenses do not contain a component that explicitly reflects the additional costs related to the number of customers expected to be added during the budget period. In most Operational and Administrative areas of Delta, as well as other utilities, the specific impact of an individual customer addition would be practically obscure. While the non-gas expenses do change over time as a result of new customer additions, these changes take place because systems require updating and enlarging, crews have to be added, etc. which generally occur as the needs arise, not with each customer or groups of customers.
(d) See response to parts (a), (b) and (c), above.
(e) See part (b), above.
(f) See part (c), above.

WITNESS: John Hall

Notes

21. Reference response to AG Request No. 84. For the most recent test year used to set Delta's current rates, please provide:

a. Commission determined rate base;

b. Budgeted plant and other budgeted items includable in rate base (only total of all the individual items need be provided); and

c. Budgeted equity (12 months average).

RESPONSE:

a. $65,445,709

b. Delta did not include budgeted items in its rate base as Delta used a historical test period.

c. See the response to b.

WITNESS:

John Hall

Notes

22. Reference response to AG Request No. 72, g. Please provide the rules and procedures, notice requirements and Delta's opinion on burden of proof that are referred to in this answer. Provide actual copies of documents or other written materials with all relevant sections so indicated. Remember, the request refers to the proposed triennial review, not the annual review.

RESPONSE:

See Delta's Response to Item 18 for a discussion of procedural requirements. In regard to burden of proof, Delta believes that it has the burden of proof with respect to proposed changes in rates such as what will made as a part of the Alternative Regulation Plan. This is similar to the burden of proof that utilities have with respect to fuel adjustment clauses, gas supply clauses, environmental cost recovery mechanism, demand-side management mechanisms, and performance-based ratemaking mechanisms.

WITNESS: Steve Seelye

Notes

23. Reference response to AG Request No. 72, h. Please provide the actual procedures Delta proposes, or would propose be applicable to the 3-year review. What is sought are actual, stated procedures not for setting the annual prospective factors, but the procedures applicable for the 3-year review.

RESPONSE:

See Delta's Response to Item 18.

WITNESS: Steve Seelye

Notes

24. Reference response to AG Request No. 74. Is it Delta's opinion that the PSC can determine rules in the instant procedure? If yes, please state the basis of such belief.

RESPONSE:

Yes. Rules can be established in the instant procedure by the Commission approving provisions that are included in the tariff. This is no different than the rules established as a part of gas supply clauses, other cost recovery mechanisms or other tariffs.

WITNESS: Steve Seelye

Notes

25. Reference response to AG Request No. 82, j. State the budget assumptions regarding the timing of new customer additions (i.e. equal number each month, equal number in X summer months, actual forecasted monthly customer additions, other).

RESPONSE:

See Delta's Response to Item 20. As indicated in that response, the Company's budget is based on an estimate of an average number of customers expected to be served during the budget period (also see Delta's Response to Item 7 of the Commission Data Request dated June 4, 1999).

WITNESS: John Hall

Notes

26. Reference response to AG Request No. 94. Please explain why the CWIP balance in the year ended 1997 is several to some 17 times as high as other CWIP balances, 1995 – 1998.

RESPONSE:

The majority of the amount can be attributed to the 12" pipeline extension from Canada Mountain. Also, most of the summer and fall construction was primarily completed at December 31, 1997, but, due to timing was not transferred to plant in service until June 30, 1998, the fiscal year end.

WITNESS:

John Hall

Notes

27. Reference response to PSC request No. 8.

a. Please provide Delta general rate case expense for each year 1987 to present;

b. Please provide the estimated annual cost associated with the alternative rate mechanism; and

c. Please provide the estimated cost associated with the "....comprehensive 3-year review,..."

RESPONSE:

a. See Delta's Responses to AG's data request No. 2(c) and to AG's data request No. 11 dated June 4, 1999.

b. Once the mechanism is approved, Delta does not anticipate any outside costs as the work is planned to be completed internally.

c. See response to b.

WITNESS:

John Hall

Notes

28. Reference response to PSC 11, first paragraph.

a. How much time will the PSC have to "conduct a review of information filed?"

b. Your proposed tariff indicates that Delta will file its Annual Adjustment Component on June 1 of each year. Your proposed tariff proposes that monthly bills shall be adjusted beginning July 1. Please provide the procedural schedule consistent with the Commission conducting a "review of Information," and providing for intervention of interested parties; the serving of data requests; responding to data requests; provision for PSC Staff and intervening parties to submit their views to the Commission; hearing on contested issues; briefing schedule; deliberation time for Commission; and issuance of Commission Order. Please provide the requested procedural schedule commencing on June 1, with the ACC filing, and indicate the number of days to be allowed for each procedural event.

c. Please explain how your procedural schedule is consistent with Commission statutory responsibility to ensure fair, just and reasonable rates.

d. Please explain how your procedural schedule is consistent with due process for the PSC Staff and intervening parties.

RESPONSE:

a. See Delta's Response to Item 18 and Delta's Response to Item 6 of the Commission's Order dated July 2, 1999.

b. Delta's proposed procedural schedule is described in Item 18 and in Item 6 of the Commission's Order dated July 2, 1999. One of the major benefits of alternative regulation is that it does not involve the same sort of evidentiary process as required for a rate case. One of the keys for successfully implementing an alternative ratemaking plan is to develop a set of performance measures that can take the place of the procedural rules generally required with a rate case. We believe that Delta has developed a program that can serve as a suitable alternative to traditional regulation.

c. Because Delta's proposed alternative regulation plan includes performance measures that are generally not required as a part a general rate case proceeding, it is not necessary to implement the same type of review that is required for general rate cases. These performance measures help ensure that Delta is charging fair, just and reasonable rates. In addition, Delta has proposed a procedural schedule that is similar to the procedural schedules used in other cost recovery mechanism, for example, fuel adjustment clauses, gas supply clauses, demand-side management mechanisms, environmental cost recovery mechanisms and performance-based ratemaking mechanisms.

d. Although it is less formal than the schedule utilized in a general rate case, the procedural schedule proposed by Delta provides the opportunity for the Commission Staff to request data and propose modifications to the filing. Delta's proposed procedural schedule provides the same level of due process as fuel adjustment clauses, gas supply clauses, demand-side management mechanisms, environmental cost recovery mechanisms and performance-based ratemaking mechanisms.

WITNESS: Steve Seelye

Notes

29. Reference response to PSC 12. The term, "If an acceptable framework can be developed [determined, or established]" appears five times in your response, along with numerous activities you believe the Commission need not consider.

a. Please detail exactly and with specificity each and every procedural and substantive matter that Delta would propose, the sum total of which defines the referenced "framework."

b. For each item that Delta suggests the Commission need not consider, mention and explain exactly which proposed "framework" components obviate a need for Commission consideration of each item.

RESPONSE:

a. See Delta's Response to Item 18 as well as the tariff sheets filed in this proceeding.

b. A fully allocated cost of service study is not required because the proposed mechanism defines the allocation methodology that will be utilized to determine rates. It will not be necessary to delve into rate design issues because the proposed mechanism defines the allocation methodology that will be utilized to determine rates. It will not be necessary to analyze pro-forma adjustment because the mechanism utilizes budgeted costs for determination of the AAC and actual historical costs for the determination of the AAF. It will not be necessary to examine the terms and conditions set forth in the utility's rate schedules because the mechanism does not modify the rate schedules.

WITNESS: Steve Seelye

Notes

30. Reference response to PSC-24, b. The Commission can prescribe in the current proceeding the types of costs that are not recoverable through the mechanism.

a. If an intervening party took the position that executive salary monies included in a budget were too high, would that be a "type" of cost that the Commission could now, in this proceeding, determine is not recoverable through the mechanism or would that be an allowable type of cost that is, in this example, a "type" of expense that is allowable, but allegedly too high in amount?

b. If executive salaries are normally the type of cost allowable under the proposed mechanism, explain how the Commission Staff or other intervening party would acquire the data addressing the amount of executive salary monies, and how that party would present its finding and recommendation to the Commission under whatever annual procedural requirements Delta thinks are appropriate.

RESPONSE:

a. See Delta's Response to Item No. 24-b in the PSC data request dated June 4, 1999.

b. To obtain information concerning executive salaries, or for any other cost item, the Commission could request this information from Delta and the company could provide it. The Commission could then consider this at a technical conference.

WITNESS: Steve Seelye

Notes

31. Reference response to AG Request No. 109.

a. Please explain how the Company proposes to include the adjustments or disallowance Ordered by the Commission. You response should include a discussion on whether or not the Company plans to separately identify those issues as adjustments to the budget year, and what type of supporting documentation the Company plans to include in its filing.

b. Please state whether the Company's filing will include a statement of changes in presentation or accounting for cost of service items in its ARP filing. If no such statement is anticipated, please explain why.

RESPONSE:

a. Disallowed costs will be separately identified and any necessary supporting documentation provided in the filing.

b. If there are changes in presentation or accounting for cost of service items in the Alternative Regulation Plan, then the filing will include a statement explaining the changes, as is done in GCR filings.

RESPONSE: Steve Seelye

CASE NUMBER:

99-046

Filed 7/30/99

COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

ALBERT B. CHANDLER III
ATTORNEY GENERAL

1024 CAPITAL CENTER DRIVE
FRANKFORT, KY 40601-8204

JUL 30 1999

July 30, 1999

Hon. Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, Kentucky 40601

Re: The Matter of Delta Natural Gas Company, Inc.
Experimental Alternative Regulation Plan, Case No, 99-046

Dear Ms. Helton:

Please find enclosed the original and 12 copies of the Attorney General's Prefiled Testimony in the above captioned matter. The documents consist of testimony of Robert Henkes, Dr. Carl G. K. Weaver, and Thomas Catlin. Copies of the testimonies were served on all parties listed in the Certificate of Service.

Sincerely,

Dennis Howard, II
Assistant Attorney General

O:\Betsy\DELTA\transforpref.wpd

CERTIFICATE OF SERVICE

I certify that a true and accurate copy of the foregoing was mailed by first class mail, postage pre-paid, on this 30th day of July, 1999, to:

ROBERT M WATT III ESQ
STOLL KEENON & PARK LLP
201 EAST MAIN STREET
LEXINGTON KY 40507-1380; and

JOHN F HALL
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391.

Assistant Attorney General

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

JUL 30 1999

PUBLIC SERVICE
COMMISSION

In the Matter of:

DELTA NATURAL GAS COMPANY, INC	)	
TO IMPLEMENT AN EXPERIMENTAL	)	Case No. 99-046
ALTERNATIVE REGULATION PLAN	)	

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF
THE OFFICE OF RATE INTERVENTION
OF THE ATTORNEY GENERAL FOR THE
COMMONWEALTH OF KENTUCKY

JULY 30, 1999

Delta Natural Gas Company
Case No. 99-046
Direct Testimony of Robert J. Henkes

TABLE OF CONTENTS

I. **STATEMENT OF QUALIFICATIONS**

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes and my business address is 7 Sunset Road, Old Greenwich, Connecticut 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a founder and principal of the firm of Henkes Consulting, which is a financial management consulting firm specializing in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and/or presented numerous testimonies in rate proceedings involving electric, gas, telephone and water companies in a number of jurisdictions including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Ohio, Pennsylvania, Vermont, the U.S. Virgin Islands and before the Federal Energy Regulatory Commission ("FERC"). A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I supplementing this direct testimony. All of my regulatory work has been on behalf of the ratepayers.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to my current position, I was a Principal of The Georgetown Consulting Group, Inc. for the last 20 years, during which I performed the same type of consulting services as I am currently rendering through Henkes Consulting. Prior to my association with the Georgetown Consulting Group, Inc., I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the Management Consulting Division of Touche Ross & Co. for six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of financial areas including cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science, received from the University of Utrecht, The Netherlands in 1966; a Bachelor degree in Marketing, received from the University of Puget Sound in 1971; and an MBA degree in Finance, received from Michigan State University in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF THIS TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony regarding various aspects of the petition of Delta Natural Gas Company ("Delta" or the "Company") to implement an experimental alternative regulation plan.

In developing this testimony, I have reviewed and analyzed the Company's petition; testimonies, exhibits, workpapers and filing requirements; responses to interrogatories and other relevant financial documents and data.

III. **CASE OVERVIEW**

Q. MR. HENKES, COULD YOU PROVIDE AN OVERVIEW OF THE COMPANY'S PROPOSED EXPERIMENTAL ALTERNATIVE REGULATION PLAN ("ARP") IN THIS PROCEEDING?

A. Yes. Delta has proposed an ARP of which the primary objective is to ensure that the Company's actual achieved return on equity rate falls within a range found to be fair, just and reasonable by the Commission. With regard to the return on equity range, the Commission would establish a "zone of reasonableness" and the proposed ARP would then automatically keep the Company's return on equity rate within this range. Delta has proposed that the return on equity ("ROE") zone of reasonableness to be used in the ARP be the ROE range authorized by the Commission in the Company's most recent base rate case, i.e., a range of 11.1% to 12.1% with a mid-point of 11.6%. The proposed ARP consists of three rate surcharge[1] components:

- Annual Adjustment Component (AAC)
- Actual Adjustment Factor (AAF)
- Balancing Adjustment Factor (BAF)

The AAC represents an annual surcharge to adjust rates for an upcoming fiscal year during the proposed 3-year experimental period in order to bring the Company's ROE to the mid-point of the fair, just and reasonable ROE range (11.6%). The AAC is determined based on Delta's financial budget approved by its Board of Directors prior to the beginning of the particular

[1] These surcharges could be positive, in case of a required rate increase, or negative, in case of a required rate decrease.

upcoming fiscal year. If this financial budget indicates a projected ROE that is higher than the ceiling level (12.1%) or lower than the floor level (11.1%) of the proposed ROE range, the AAC rate would be set in such a way as to equalize the projected ROE with the ROE range mid-point rate of 11.6%. There are two proposed limiting provisions in the determination of the AAC rate. First, if the AAC involves a positive surcharge (rate increase) that would increase Delta's aggregate rates to an "uncompetitive level", the Company would limit the AAC rate increase to a level that, presumably, would leave the Company's overall rates competitive[2]. The second limiting provision is that an AAC rate involving a rate increase could not exceed 5% of Delta's total actual operating revenues for the immediately preceding fiscal year.

After the AAC has been in effect for a full fiscal year, the Company would perform a true-up calculation based on actual financial results for this fiscal year. This is where the proposed AAF surcharge rate comes into play. If the true-up indicates that the Company's actual achieved ROE for the fiscal year is within the range of 11.1% to 12.1%, there would be no AAF surcharge rate. However, if the Company's actual achieved ROE is below 11.1%, a revenue deficiency is calculated based on the revenue requirement necessary to bring Delta's ROE back up to 11.1%. Conversely, if the Company's actual achieved ROE is above 12.1%, a revenue excess is calculated in order to reduce Delta's ROE down to 12.1%. The AAF represents the positive (rate increase) or negative (rate decrease) surcharge to accomplish this

---

[2] The Company's filing and accompanying testimonies offer no details as to how this would be accomplished or where it would draw the line as to when its rates would move from being competitive to being uncompetitive.

ROE true-up process.

The third ARP rate surcharge component, the BAF, represents another true-up mechanism which would start after the completion of the first year that the AAF surcharge rate has been in effect. The purpose of the BAF is to reflect any over- or under-recoveries realized through the application of the AAF and/or through the application of the BAF surcharge rate for the preceding fiscal year.

Q. ARE THERE ANY SELECTIVE ASPECTS OF THE COMPANY'S PROPOSED POSITION IN THIS PROCEEDING WHICH YOU WOULD LIKE TO HIGHLIGHT AT THIS POINT?

A. Yes. First, a major point claimed in the Company's filing is that its proposed alternative regulation mechanism would be less resource intensive and costly than the traditional base rate case ratemaking process and, therefore, would result in cost savings to both the Company and the Commission.

Second, the Company appears to suggest in its filing that its proposed ARP should not be considered a novel ratemaking approach in Kentucky in that the Commission has recently approved performance-based rate mechanisms for Columbia Gas of Kentucky, Western Kentucky Gas Company, and Louisville Gas and Electric Company and has approved other types of altenative rate mechanisms for a number of Kentucky utilities in the form of gas supply, environmental cost, and demand-side management cost recovery mechanisms.

Third, while Delta's proposed ARP is primarily based on the operation of the Rate Stabilization and Equalization Plan ("Rate RSE") adopted by the Alabama Gas Corporation, Delta also claims that, due to certain components built into its proposed ARP that are not present in Alabama Gas Corporation's Rate RSE, the proposed ARP represents a significantly improved version of Rate RSE.

Fourth, through the testimony of its witness Seelye, Delta amended its originally proposed ARP by incorporating in its proposed Plan certain components which it claims to be "performance-based cost controls". The first of these "performance-based cost controls" is that in establishing the AAF surcharge rate, the Company's actual non-gas O&M expenses will be compared to the so-called "Indexed O&M Expenses", representing the non-gas O&M expenses approved in Delta's last rate case, increased on a compounded annual basis by the CPI-U inflator. If the previous fiscal year's actual non-gas O&M expenses fall within $\pm$ 1.50% of the "performance-based" Indexed O&M Expense benchmark, then this actual non-gas O&M expense level will be used to compute the achieved ROE in establishing the AAF surcharge rate. If these same actual non-gas O&M expenses exceed the Indexed O&M Expense benchmark by more than 1.50%, then Delta would only be able to recognize 50% of this actual non-gas O&M expense excess for purposes of calculating the AAF. Conversely, if these same actual non-gas O&M expenses are lower than the Indexed O&M Expense benchmark by more than 1.50%, then Delta would be allowed to increase the actual expenses used to calculate the AAF by 50% of the amount by which the actual expenses are below 98.50% of the Indexed O&M Expense benchmark.

The second "performance-based cost control" component is that the common equity ratio in Delta's capitalization for purposes of computing the AAF will be limited to no more than 60%.

Q. WHAT WILL YOU BE DISCUSSING IN THE REST OF THIS TESTIMONY?

A. In the remainder of this testimony I will address certain selected issue areas concerning Delta's proposed ARP, based upon which I have concluded that the Company's proposed Plan is not in the public interest and, for that reason, should be rejected by the Commission.

IV. **DISCUSSION OF ISSUES**

1. Opportunity versus Guarantee to Earn Fair Rate of Return

Q. DO YOU BELIEVE THAT THE END RESULT OF THE COMPANY'S PROPOSED ARP IS A VIRTUAL GUARANTEE THAT IT WILL EARN ITS AUTHORIZED RETURN ON EQUITY?

A. Yes. This is not only evident from the structure of its proposed ARP, it is essentially admitted by Delta in its filing:

> "The proposed alternative ratemaking mechanism would ensure [read: guarantee] that Delta's rate of return falls within the range authorized by the Commission" (Page 3 of Filing)

> "The primary objective of the proposed mechanism is to establish a process for ensuring that the utility's rate of return falls within the range found to be fair, just and reasonable by the Commission." (Page 10 of Filing)

This would be accomplished by

> "....automatically making rate adjustments to keep Delta's rate of return within the range authorized by the Commission." (Page 3 of Filing)

The way the proposed Alternative Regulation Plan is set up and designed by the Company, I would suggest calling it a "GRAM", or "Guaranteed ROE Adjustment Mechanism", rather than an ARP.

Q. IS THE COMPANY'S PROPOSAL INCONSISTENT WITH GENERALLY ACCEPTED

RATEMAKING PRINCIPLES?

A. Yes. Whether a utility is being regulated under traditional ratesetting rules or performance-based/alternative ratemaking mechanisms, one of the most important tenets of ratemaking is that the utility should be afforded the *opportunity* to earn its authorized rate of return, rather than be guaranteed those earnings. This opportunity could involve upward as well as downward risks of achieving the authorized rate of return and this risk presumably is built into the allowed ROE. In fact, the Company itself seems to acknowledge this important ratemaking priciple:

> "One of the guiding principles of rate regulation is to establish rates that will provide the utility an opportunity to earn a fair, just and reasonable return on invested capital." (Page 2 of Filing)

Q. WHAT THEORY SUPPORTS DELTA'S PROPOSAL THAT IT IS APPROPRIATE TO IMPLEMENT AN ALTERNATIVE RATE MECHANISM THAT VIRTUALLY GUARANTEES THE ACTUAL ACHIEVEMENT OF ITS AUTHORIZED ROE?

A. Delta claims that under the traditional ratemaking rules under which it has been regulated up to this point, it has not been given a reasonable assurance of earning a rate of return in the range established by the Commission. In this regard, the Company states in response to data request AG-9:

> "...a utility that consistently earns less than the allowed rate of return or which has averaged significantly less than the allowed rate of return for a long period of time cannot be said to have had a reasonable assurance of earning the allowed rate of return."

At the same time, however, Delta confirms in response to date request AG-60 that, "Traditional regulation is certainly consistent with regulatory practice in Kentucky and continues to be a reasonable method for setting rates." Furthermore, while the Company appears to blame the regulatory process for its inability to earn its allowed rate of return, it confirms in its response to data request PSC-1 that it has not performed any formal analyses to determine why it has been unable to earn its authorized rate of return over the last 10 years.

Q DO YOU HAVE ANY OTHER COMMENTS REGARDING THE FACT THAT DELTA'S PROPOSED ARP VIRTUALLY GUARANTEES THE ACHIEVEMENT OF THE COMPANY'S ALLOWED ROE?

A. Yes. In my opinion, Delta's proposed ARP contains less incentives for cost controls/reductions and operational and financial improvements than would be present under traditional regulation. The proposed ARP, with its automatic rate adjustments and all of the built-in true-up mechanisms, will virtually guarantee that the Company will earn its authorized ROE. As will be discussed in more detail in subsequent sections of this testimony, the proposed "performance-based" benchmarks included in the ARP are unrealistic or inappropriate in other ways and cannot be seriously referred to as cost control or cost reduction incentives. By contrast, under continued traditional regulation without the prospect of a virtually guaranteed ROE performance, the Company will have a lot more incentive to either control or reduce its costs and/or enhance its revenues.

2. Claimed Benefits of the Proposed ARP

A. *Cost Savings*

Q. WHAT DOES THE COMPANY CLAIM TO BE A PRIMARY BENEFIT OF ITS PROPOSED ARP AS COMPARED TO THE TRADITIONAL RATE REGULATION PROCESS?

A. As stated on pages 4 and 5 of its Filing, Delta claims that the proposed ARP mechanism would be less resource intensive and costly than the traditional ratemaking process through base rate cases and, therefore, would result in cost savings to both the Company and the Commission. In this regard, the Company also states on page 4 of its Filing:

> "Although the alternative rate mechanism would likely involve a comprehensive 3-year review, it is anticipated that such a review would be less resource intensive and costly than a full-blown rate case."

Q. DO YOU AGREE WITH THIS CLAIM?

A. No, I do not. In this regard, let us first consider the rate case costs incurred by the Company in its last 5 rate cases under traditional regulation. The responses to data request AG-11 and supplemental data request AG-2, show the following relevant information:

Rate Case Filing Date	Rate Case Costs (Out-of-Pocket)
1. 06/18/82	Data Not Available
2. 07/06/84	$ 58,820
3. 05/31/85	$ 65,223
4. 12/14/90	$ 87,000
5. 03/14/97	$129,000

What can be concluded from the above table is that:

(1) as measured from June 1982 through June 1999, the Company has had 5 rate cases during this 17-year traditional regulation period; this averages out to be 1 rate case in every 3.4 years.

(2) the total cumulative actual out-of-pocket rate case expenses incurred by Delta during the last 4 rate cases, and in the approximate 15-year traditional regulation period from July 1984 through June 1999, amount to $340,043; this averages out to be approximately $23,000 per year ($340,043 / 15 yrs).

Q. WHAT ARE TYPICAL OUT-OF-POCKET RATE CASE EXPENSES FOR DELTA'S RATE CASES?

A. The major out-of-pocket rate case expenses typically consist of consultant and legal fees, printing costs and other supplies, newspaper advertising, and out-of-pocket costs incurred during hearings. For example, the response to data request PSC-49(b) in the Company's last rate case, Case No. 97-066, shows the following breakout of the Company's projected out-of-pocket rate case expenses for that proceeding:

-	Consultants	$ 30,000
-	Legal	$ 20,000
-	Printing & Other Supplies	$ 5,000
-	Newspaper Advertising	$ 20,000
		$ 75,000

Q. WHAT ACTIVITIES WOULD BE INVOLVED WITH REGARD TO DELTA'S PROPOSED ARP?

A. Unlike traditional regulation, Delta's proposed ARP would require several annual review processes. First, the Company would annually be required to file its proposed AAC surcharge factor based on the budget approved by the Board of Directors for the particular AAC period. As part of this annual AAC filing, Delta not only has to prepare and submit the filing itself, but also has to prepare and submit to the Commission and all other interested parties the following filing requirement information:

- Annual Operating Budget, as approved by Delta's Board of Directors.
- Statements detailing the monthly budgeted net revenues and MCF sales of each rate class billing block for all applicable rate schedules.
- Statements detailing monthly forecasts of net revenues, by rate class billing block, for an additional three months beyond the budget year, along with a monthly forecast of MCF sales and transportation volumes, by rate class billing block, for an additional six months beyond the budget year.
- Statements of Budgeted Income setting forth the calculations of expected net income available for common equity as well as the ROE for the budget year, along with supporting documentation.

Of course, once all of this AAC filing information has been received by the Commission and other interested parties, they will have to spend considerable time and resources to verify the appropriateness of all of this budgeted filing information and to potentially adjust and amend the Company's AAC filing material to reflect PSC ratemaking principles or other appropriate ratemaking adjustments. This was acknowledged in Delta's response to data request AG-24:

> "The AG and any other party with a legitimate interest will have the opportunity to review the appropriateness of the use of Delta's budget for cost recovery through the AAC, and will have the opportunity to recommend adjustments and amendments thereto."

This review and analysis process will also require Delta to provide additional information in the form of, for example, responses to data requests, documentation to be prepared for and provided during "technical discovery" conferences, etc.

Next, the Company would annually be required to file its proposed AAF surcharge factor based on actual financial information during the just-completed AAC period. As part of this annual AAF filing, Delta not only has to prepare and submit the filing itself, but also has to prepare and submit to the Commission and all other interested parties the following filing requirement information:

- Statement showing the actual net revenues and MCF sales for the most recent fiscal year.
- Statement of Actual Income setting forth the calculations of actual net income available for common equity as well as the return on common equity, along with the supporting documentation.

Again, similar to the activities for the AAC review and analyses, the Commission and other interested parties will have to perform an even more thorough review and analysis process to verify the appropriateness of the actual results underlying the proposed AAF surcharge and potentially make adjustments to reflect appropriate ratemaking principles or disallow actual expenses that are deemed not to be appropriate for rate inclusion. As confirmed in Delta's response to data request AG-25:

> "The AG and any other party with a legitimate interest will have the opportunity to review the appropriateness of the actual historical costs used in the determination of the AAF, and will have the opportunity to recommend adjustments thereto."

These review and potential adjustment activities would also require additional document preparation and resource allocation on the part of Delta.

Finally, the proposed ARP also requires an annual filing of the BAF surcharge factor. As part this annual filing, Delta would submit a statement showing a reconciliation of (1) amounts that should have been recovered or refunded under the AAF surcharge and previous

BAF surcharges, and (2) amounts actually recovered or refunded under these surcharges. Delta would also file the calculations and all supporting documentation for the upcoming BAF factor.

Q. WHAT WOULD HAVE TO HAPPEN IF THE "ZONE OF REASONABLENESS" ROE RANGE INITIALLY ESTABLISHED FOR THE ARP WERE TO CHANGE DURING THE ARP EXPERIMENTAL PERIOD?

A. As stated in its response to supplemental data request AG-14, the Company envisions that such a change would most likely have to be investigated and effectuated through a Commission-ordered rate proceeding.

Q. WHAT IS THE COMPANY'S POSITION AS TO THE COSTS ASSOCIATED WITH ALL OF THESE ANNUAL ARP ACTIVITIES YOU JUST DESCRIBED?

A. When the Company was asked in supplemental data request AG-27 "...the estimated costs associated with the alternative rate mechanism; and the comprehensive 3-year review" its only response was that "...Once the mechanism is approved, Delta does not anticipate any outside costs as the work is planned to be completed internally."

I find the above-referenced response to be somewhat disingenuous and insincere. Delta is essentially stating that there will be no incremental costs associated with all of the annual activities associated with the ARP implementation. In my opinion, this position cannot be taken seriously. As shown in the previous table in this testimony, for the prior rate case,

Case No. 97-066, the Company projected incurring at least $25,000 for such out-of-pocket expenses as newspaper advertising, printing and other supplies. Assuming that this same out-of-pocket amount were to be incurred on an annual basis for the ARP, this would already be more expensive than the average annual out-of-pocket rate case expense of $23,000 incurred by Delta during the last 15 years under traditional regulation. Furthermore, since the proposed ARP implementation ultimately involves 3 different annual filings (for the AAC, AAF and BAF), each of which filings would require substantial filing requirements and document preparation and submittals to the Commission and any other interested parties, I believe that the proposed ARP's annual out-of-pocket costs will be substantially higher than $25,000. In addition, the Company may incur overtime expenses associated with the preparation, presentation and defense of all of the surcharge components of the proposed ARP. While such overtime expenses do not represent "outside costs", they represent incremental expenses that would not have been incurred absent the ARP and should therefore clearly be considered costs associated with the ARP mechanism. Finally, while the Company "does not anticipate any outside costs"[3] (e.g., in the form of outside consultants and/or outside legal assistance), this is purely an opinion expressed at this time which may change if the Company were to be allowed to implement its proposed ARP.

Q. DO YOU BELIEVE THAT THERE WILL BE COST SAVINGS FOR THE COMMISSION AND OTHER INTERESTED PARTIES, SUCH AS THE OFFICE OF RATE INTERVENTION, UNDER THE PROPOSED ARP AS COMPARED TO THE

[3] Per response to supplemental data request AG-27.

TRADITIONAL REGULATORY PROCESS?

A. No. As discussed before, under traditional regulation, the Company has had one rate case every 3.4 years during the last 17 years. Under the proposed ARP, there will eventually be three separate rate surcharge filings on an annual basis, requiring review and analysis activities on the part of the Commission and other interested parties that are equivalent to "mini rate cases". Therefore, when considering the regulatory costs under traditional regulation versus the proposed ARP on a more long-term basis, I do not believe that the Commission and other interested parties will incur cost savings under the proposed ARP.

B. *Claimed Ratepayer Benefits*

Q. DOES THE COMPANY CLAIM THAT ITS PROPOSED ARP RESULTS IN BENEFITS TO ITS RATEPAYERS?

A. Yes. Delta claims that its proposed ARP will benefit both its ratepayers and shareholders because, among other things, the Plan presumably will result in rate and earnings stabilization.

Q. DO YOU BELIEVE THAT THE PROPOSED ARP WILL RESULT IN RATEPAYER BENEFITS?

A. No, I do not. I believe that the proposed ARP will result in annual rate changes for Delta that will certainly benefit the Company's shareholders, but will not benefit the ratepayers when compared to the average annual rate changes experienced historically under traditional regulation. The response to data request AG-11 shows the following historic information:

Rate Case Filing Date	Rate Increase Granted
1. 06/18/82	$1,306,000
2. 07/06/84	$1,370,000
3. 05/31/85	$ 683,000
4. 12/14/90	$2,050,000
5. 03/14/97	$1,786,000
	$7,195,000

The data in the above table indicate that during the 17-year traditional regulation period from June 1982 through June 1999, Delta's ratepayers experienced an average annual rate increase of approximately $423,000[4]. By contrast, the historical test of the proposed ARP for the three fiscal years ended 6/30/96, 6/30/87 and 6/30/98 shown in Schedules A and B attached to the Company's Filing indicate that if the ARP had been in effect for that three-year period, the total cumulative rate change for this three-year period would have been $4,030,517[5]. This would translate into an average annual rate increase amount of approximately $1,344,000, or more than 3 times as high as the average annual rate increase of $423,000 experienced under traditional regulation.

Q. HAS THE COMPANY QUANTIFIED ANY RATEPAYER BENEFITS FROM THE PROPOSED ARP?

A. No. In response to data request AG-79, Delta acknowledges that it has developed no numerical calculations showing that the proposed ARP benefits Delta's customers.

---

[4] $7,195,000 / 17 yrs = $423,235

[5] Combined impacts of AAC and AAF surcharges during the referenced three-year period

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING THE PROPOSED ARP FROM THE VIEWPOINT OF RATEPAYER BENEFITS?

A. It is my opinion that an ARP or PBR mechanism should only be considered by the regulator *if the implementation of these alternative ratemaking mechanisms provide clear and quantifiable incremental benefits to the ratepayers that would not be achievable under traditional regulation.* This has not been proven by the Company in this proceeding. In fact, I have concluded that the proposed ARP will provide incremental benefits to Delta's shareholders only. The ratepayers will be worse off than under traditional regulation.

3. <u>Comparison of Proposed ARP to Other PBR Mechanisms Recently Approved by the KPSC</u>

Q. IN ITS FILING, DELTA ESSENTIALLY EQUATES ITS PROPOSED ARP WITH PERFORMANCE-BASED RATE ("PBR") MECHANISMS RECENTLY APPROVED BY THE COMMISSION FOR COLUMBIA GAS OF KENTUCKY, WESTERN KENTUCKY GAS COMPANY, AND LOUISVILLE GAS AND ELECTRIC COMPANY. COULD YOU COMMENT ON THIS?

A. Yes. First, it should be recognized that Delta's proposed ARP goes far beyond these three PBRs in terms of the type of costs that can be recovered through automatic, reconcilable rate adjustment mechanisms. Delta's proposed ARP applies to all of its non-gas costs, including non-gas O&M expenses, depreciation expenses, taxes, and cost of capital. In addition, Delta will continue to recover all of its gas supply costs on a dollar-for-dollar basis through its Gas Cost Recovery ("GCR") clause. In summary, as confirmed in the response to supplemental data request AG-11, Delta is already recovering approximately 60%[6] of its total operating costs on a dollar-for-dollar basis through a fully-reconcilable GCR clause and is now requesting an additional automatic adjustment mechanism to recover the remaining 40% of its total operating costs and receive a virtually guaranteed KPSC-authorized ROE rate. By contrast, each of the previously referenced three PBRs only concern performance-based ratemaking within each of the utilities' GCR clauses[7], relating to gas procurement and off-system sales. Specifically, the costs subject to the PBR mechanisms of Columbia Gas, Western Kentucky Gas and LG&E involve gas commodity, pipeline transportation, and/or gas storage costs and off-system sales, all of which elements flow through the GCRs of these utilities. For each of these gas cost/off-system sales elements, the utilities proposed market-based or other hard-to-achieve benchmarks to which their actual gas costs/off-system sales would then be compared. Generally, if the actual gas costs come in lower than these tough benchmarks, there would be a reward (for example, in the form of a 50/50 sharing of the cost savings) and if the actual gas costs are higher than the performance benchmarks, there would be a penalty (for example, by not being allowed to recover a portion of the actual costs).

Each of these three other Kentucky utilities had also requested that their respective proposed PBR mechanisms be allowed to include non-gas related labor and other O&M expenses incurred in the implementation of the PBRs, such as, for example, transaction costs associated with risk management. However, in each of these three PBR cases, the Commission

[6] Representing the approximate ratio of Delta's gas supply costs to its total operating costs.

[7] For some Kentucky gas utilities referred to as Gas Cost Adjustment ("GCA") clauses.

ruled that such non-gas related O&M expenses should not be recovered in the proposed PBR recovery mechanisms. This would appear to indicate that the KPSC does not believe it appropriate for non-gas related O&M expenses to be recoverable through an automatic adjustment clause.

It is apparently also KPSC policy that the performance benchmarks to be included in ARP or PBR mechanisms should be set at levels that are difficult to reach and ***represent an improvement*** over what the utility is already achieving under its current regulatory process. The Commission made this ruling in the LG&E PBR proceeding, Case No. 97-171, where it ruled with regard to the Company's Capacity Release PBR component that ..."LG&E should be required to reach a threshold [benchmark] level before it shares capacity release revenues. LG&E has already been engaged in capacity release activities and has attained some expertise in this area. The PSC believes that LG&E should exhibit an improvement over its past practice before it shares in these revenues."[8]

Q. COULD YOU NOW SUMMARIZE WHY AND HOW THE PREVIOUSLY REFERENCED THREE PBR MECHANISMS DIFFER FROM DELTA'S PROPOSED ARP?

A. Yes. First, each of the three PBR mechanisms involve gas supply related cost and/or off-system sales elements flowing through their respective GCRs and cannot include any non-gas type of expenses such as O&M expenses. By contrast, Delta's proposed ARP includes all of its non-gas expenses and taxes, including its cost of capital.

[8] KPSC Order dated September 30, 1997, Case No. 97-171, at 3.

Second, the three PBR mechanisms include tough benchmarks that must represent improvements over what the utilities were achieving previously. It is only after "beating" these challenging benchmarks that any sharing of cost savings can accrue to the shareholders. By contrast, Delta's amended ARP does not include tough benchmarks that represent an improvement over its prior performance. Delta's proposed "Indexed O&M Expense" performance benchmark is merely based on the Company's O&M expenses allowed in its most recent rate case, increased on an annual compounded basis by the CPI-U inflator. As will be discussed in more detail later on in this testimony, if this performance benchmark had been used during the most recent historic 5 years, it would have resulted in annual "Indexed O&M Expense" levels that are much higher than the Company's actual annual O&M expenses for that same 5-year period. Delta's second proposed performance benchmark, the 60% equity ratio limitation in the capital structure used to determine the Company's actual achieved rate of return, is also inappropriate for reasons that will be discussed later on in this testimony.

Third, the three PBRs focus primarily on incentives to improve financial and operational performance and achieve actual cost savings in which there is the potential for the utilities to share. These PBRs would appear to represent reasonable performance-based incentive mechanisms with the potential of <u>*incremental benefits to the ratepayers which would not be available to the ratepayers under traditional regulation*</u>. By contrast, Delta's proposed ARP focusses primarily on the virtual guarantee that it will earn its authorized ROE, without any real financial and operational improvements and cost saving incentives built in and with no incremental benefits to the ratepayers over and above what they would have experienced under the current traditional regulation. In fact, the only incremental benefits from the proposed ARP would accrue to Delta's shareholders.

Fourth, the three PBRs are fairly simple to understand, implement and administer, with little opportunity for disputes and "gaming", whereas Delta's ARP is complicated, cumbersome to implement and administer, with opportunities for disputes and "gaming".

4. Comparison of Proposed ARP to Alabama Gas Corporation's Rate RSE

Q. DELTA'S PROPOSED ARP IS MODELED AFTER THE RATE STABILIZATION AND EQUALIZATION PLAN ("RATE RSE") OF THE ALABAMA GAS CORPORATION. HOWEVER, DELTA ALSO CLAIMS THAT THE PROPOSED ARP REPRESENTS AN IMPROVED VERSION OF RATE RSE DUE TO CERTAIN COMPONENTS BUILT INTO ITS PLAN THAT ARE NOT PRESENT IN ALABAMA'S RATE RSE . COULD YOU COMMENT ON THIS?

A. Yes. It is true that Delta's proposed ARP represents a significant improvement over Alabama Gas Corporation's Rate RSE, but *only from the viewpoint of Delta's shareholders*. Based on what will be discussed below, it is my opinion that Delta's ratepayers under the proposed ARP are worse off than Alabama Gas Corporation's ratepayers under Rate RSE.

Q. WHAT IS THE UNDERLYING REASON FOR DELTA'S CLAIM THAT ITS PROPOSED ARP IS AN IMPROVED VERSION OF ALABAMA'S RATE RSE?

A. Delta states that its proposed ARP represents an improvement over Alabama's Rate RSE "by including a mechanism that incorporates an actual adjustment and a balancing adjustment that will allow Delta to reconcile the actual results for a fiscal year." (Hall testimony pages 2 and 3). As indicated in the response to data request PSC-20, while the Alabama Rate RSE plan also utilizes budgeted data on an annual cycle (equivalent to Delta's proposed AAC), unlike Delta's Plan (through the AAF actual reconciliation factor), the Alabama mechanism never fully reconciles to actual historic costs.

Q. IS THIS TRUE?

A. Yes. The Alabama Rate RSE plan ultimately reconciles 9 months of the budget year (equivalent to Delta's proposed AAC budget year) with actual historic results. Apparently, the last three months of Alabama's budget year are not reconciled with actual results. Therefore, Delta can indeed state that the Alabama Rate RSE plan never gets *fully* reconciled to actual results. Delta's plan allows for the reconciliation of the full budget year with full 12 months of historic results.

Q. DOES THE DELTA PROPOSAL DIFFER IN ANY OTHER SIGNIFICANT WAY FROM THE ALABAMA RATE RSE?

A. Yes. Delta's Plan proposes to return to ratepayers (through an AAF rate refund) actual ROE earnings above the earnings band ceiling of 12.1% and charge to ratepayers (through an AAF rate increase) actual ROE earnings below the earning band floor of 11.1% up to 11.1%. By contrast, <u>*the Alabama Rate RSE Plan allows for a rate decrease when the actual ROE is above*</u>

the authorized ROE, but does not allow for a rate increase when the actual ROE is below the authorized ROE[9]. Thus, unlike Delta's proposed ARP, the *ex-post* reconciliation process in Alabama's Rate RSE plan can never result in a prospective rate increase based on retroactive budget-to-actual result comparisons. This fact is not mentioned by Delta in its filing, accompanying testimonies or responses to data requests.[10]

Q. WHAT ARE SOME OTHER DIFFERENCES BETWEEN DELTA'S PROPOSED ARP AND THE RATE RSE PLAN OF THE ALABAMA GAS CORPORATION?

A. As confirmed in the Company's responses to data request PSC-32 and supplemental data request AG-12 (b) (c), the following are also differences between Delta's proposed ARP and the Rate RSE plan of the Alabama Gas Corporation:

- The annual rate increases under the Alabama Rate RSE plan are capped at 4% of actual prior year's operating revenues. Delta's proposed annual rate increase cap is at 5% of actual prior year's operating revenues.
- the "Indexed O&M Expenses" in Alabama's Plan are based on that company's prior year's actual O&M expenses, increased by one year's worth of CPI inflator. Delta's "Indexed O&M Expenses" are based on the O&M expenses allowed in its most recent rate case, increased by an annually compounded CPI-U inflator. As described in supplemental data

[9] In its response to supplemental data request AG-12(a), Delta acknowledged that "...the Alabama Plan does only provide for downward adjustments to rates pursuant to the "true-ups..."

[10] In this regard, particular reference is made to the Company's response to data request PSC-32 in which the Commission requested that, "Delta list and describe the differences in Delta's proposal and Alabama Gas Company's current Rate Stabilization and Equalization Plan."

request AG-12 and summarized in the table below, Delta's performance-based benchmark O&M expense levels per customer would be much lower using Alabama's "Indexed O&M Expense" method than using Delta's proposed "Indexed O&M Expense" method:

	AAF-Recoverable O&M Exp. Under Delta's Proposed "Indexed O&M Expense" Method	AAF-Recoverable O&M Exp. Under Alabama's Proposed "Indexed O&M Expense" Method
1994	$248.80/ customer	$247.69/ customer
1995	$242.55	$243.16
1996	$252.89	$245.91
1997	$251.00	$243.47
1998	$251.75	$237.14

- Delta's Plan provides that if its actual O&M expenses are in excess of the "Indexed O&M Expenses"plus 1.5 %, Delta would return to its ratepayers 50% of this cost overrun. Under the Alabama Plan, if the actual O&M expenses are in excess of the "Indexed O&M Expenses"plus 1.25 %, Alabama returns to its ratepayers 75% of this cost overrun.

In summary, while Delta claims that it has improved upon the Alabama Rate RSE Plan, it is clear that all "improvements" concern the interests of the stockholders and not the ratepayers.

5. Other Inappropriate Aspects of the Proposed ARP

A. *Rate Cap of 5% of Prior Year's Total Operating Revenues*

Q. DO YOU AGREE WITH THE PROPOSED ARP ASPECT THAT ANY AAC RATE INCREASE BE CAPPED AT NO MORE THAN 5% OF THE COMPANY'S TOTAL ACTUAL OPERATING REVENUES IN THE PRECEDING FISCAL YEAR?

A. No, I disagree for various reasons. First, the 5% cap is arbitrary. The only reason for the Company to pick this percentage is that "...this percentage is a commonly used annual price increase cap in contracts."[11]

Second, the historic average annual rate increases experienced by the Company have been a lot lower than the proposed annual 5% cap. In this regard, the response to supplemental data request AG-2, shows the following information:

Rate Case Filing Date	Rate Increase Granted (%)
1. 06/18/82	Data Not Available
2. 07/06/84	4.50%
3. 05/31/85	2.26%
4. 12/14/90	7.00%
5. 03/14/97	4.28%

The data in the above table indicate that during the 15-year period from July 1984 through June 1999, the Company had accumulated rate increases amounting to 18.04%, representing an average annual rate increase of 1.2% during this same 15-year period.

[11] Per response to data request AG-20

Third, the actual total operating revenues to which the proposed 5% cap is applied include GCR revenues. GCR rates and associated revenues are separately accounted for and recovered on a dollar-for-dollar basis through the Company's automatic GCR rate adjustment mechanism. It would not be appropriate to apply this 5% rate increase cap for the Company's non-gas operations to a revenue base that in large part consists of gas cost related GCR revenues.

Consider the folllowing situation that can exist under the Company's proposed 5% cap: assume that the Company's AAC non-gas base rate increase for a particular year is limited to 5% of the total operating revenues for the prior year (which revenues would also include GCR revenues), but for this same year the Company also receives a rate increase in its GCR rates through the separate GCR rate mechanism; this means that the ratepayers for this particular year will experience an increase in their aggregate rates that is higher than 5%. This would be inconsistent with the intent of the 5% cap component of the proposed ARP. From the response to supplemental data request AG-3 and Schedule A attached to the Company's Filing, the following information can be derived:

	FY 95-96	FY 96-97	FY 97-98
Schedule A:			
- Calculated AAC Rate Increase	$ 996,830	$3,442,407	$2,920,324
- AAC Increase Limitation Based on 5% of Prior Year's Total Revenues	$1,395,618	$1,535,563	$1,805,816
- AAC Increase to be Implemented	$ 996,830	$1,535,563	$1,805,816
Supplemental AG-3:			
- AAC Increase Limitation Based on 5% of Prior Year's Non-GCR Revenues	$ 811,248	$ 895,938	$ 850,653
- AAC Increase to be Implemented	$ 811,248	$ 895,938	$ 850,653

Thus, if one were to determine the rate increase cap for Delta's non-gas operations based on the application of the 5% cap factor to Delta's prior year's non-gas (non-GCR) operating revenues, this would have resulted in AAC increases for the above-referenced three fiscal years that are substantially lower than as currently shown on Schedule A of the Company's Filing.

B. *AAC and AAF Mechanisms*

Q. DO YOU SEE ANY POTENTIAL PROBLEMS WITH THE COMPANY'S PROPOSED AAC AND AAF SURCHARGE MECHANISMS?

A. Yes. The proposed AAC surcharge rate will be based on Delta's Board of Directors approved operating budget. The Company's operating budgets may include many "wish list" expenditures requested by department heads as part of the overall operating budget that are not really necessary for the provision of safe, adequate and reliable gas service and that may be uncovered and removed by the Commission and other interested parties if given the opportunity for a thorough and comprehensive "rate case type investigation". However, such comprehensive investigative efforts are not anticipated in the proposed ARP. In response to supplemental data request PSC-6, Delta states that "....we do not envision an extensive review of the AAC filing" and that...

> "For the filing of the AAC, the Commission would be allowed to review the budgeted costs for the upcoming fiscal year during the 30 days between Delta's filing and the implementation of the AAC. Any questions concerning the filing could be handled informally through either telephone conversations or an informal technical conference during the 30-day period." (Emphasis supplied)

Thus, under Delta's proposed position, there will not be much time and opportunity to do a thorough review of the Company's operating budget forming the basis for the AAC surcharge.

Q. DOESN'T THE COMPANY ALSO ARGUE THAT THE APPROPRIATENESS OF THE USE OF THE OPERATING BUDGET FOR THE AAC SURCHARGE IS LESS RELEVANT BECAUSE IN THE NEXT YEAR THESE BUDGETED RESULTS ARE FULLY RECONCILED WITH ACTUAL RESULTS?

A. Yes. However, it should be recognized that when the AAC budgeted results are eventually compared to actual results and it appears that the Company has overearned (due to overstated budgeted expenses or understated budgeted revenues), the Company is only required -- through the AAF surcharge -- to reduce its rates to bring the actual ROE down to 12.1%, the upper band of the proposed ROE range. Thus, the Company will have an incentive to always end up with a rate reduction AAF surcharge (due to pessimistic budget results in the annual setting of the AAC surcharge), so that it will then consistently earn at the top of the authorized ROE range.

In order to avoid this potential "gaming" situation, there must be very detailed and comprehensive reviews and analyses by the Commission and all other interested parties of Delta's operating budget for purposes of setting the annual AAC surcharge and of the actual results for purposes of setting the annual AAF surcharge to make sure that both the budgeted and actual results include approriate expense, revenue, investment and capital structure levels that are consistent with KPSC ratemaking policies and principles. However, such comprehensive reviews and analyses will not be possible under the Company's proposed ARP review process.

Q. IS THERE HISTORIC EVIDENCE THAT DELTA'S OPERATING BUDGETS HAVE CONSISTENTLY BEEN MORE PESSIMISTIC THAN ACTUAL RESULTS FOR THE SAME PERIODS?

A. Yes. As shown in the "ANALYSIS" section of the Company's Filing and summarized in data request AG-36, the Company has consistently under-budgeted its Net Income Available for Common Stock ("NIAC"):

	Actual NIAC	Budgeted NIAC	Actual vs. Budget	
			Amount	%
FY 7/95 - 6/96	$2,066,998	$1,784,600	$ 282,398	16
FY 7/96 - 6/97	$1,407,939	$ 778,850	$ 629,089	81
FY 7/97 - 6/98	$2,025,723	$ 875,900	$1,149,823	131

In addition, the response to data request AG-40 indicates that during the last 10 years, the Company's actual NIAC was, on average, about 8% higher than the budgeted NIAC that was approved by the Board of Directors for those years.

C. *Delta's Proposed "Performance-Based Cost Controls"*

Q. WHAT IS YOUR OPINION REGARDING DELTA'S PROPOSED "PERFORMANCE-BASED" COST CONTROLS BUILT INTO ITS ARP?

A. Delta has proposed two benchmarks which it refers to as "performance-based cost controls". The first is an alleged performance control that uses the Company's "Indexed O&M Expenses" as a benchmark. The second concerns a performance control that places a limit on the amount of common equity that can be included in Delta's total capitalization for purposes of computing the AAF surcharge. Mr. Seelye announces on page 8 of his testimony that because of these two items, the Company has "...integrated performance-based ratemaking concepts into Delta's Alt Reg Plan." It is my opinion that these two items which the Company calls "performance-based cost controls" represent benchmarks that are quite meaningless and that provide no incentive to the Company to improve its prior or current operations or control/reduce its costs.

Q. COULD YOU EXPLAIN THIS IN MORE DETAIL?

A. Yes. Let me first address the performance-based cost control that uses the Company's "Indexed O&M Expenses" as a benchmark. In establishing the AAF surcharge rate, the Company's actual non-gas O&M expenses will be compared to the so-called "Indexed O&M Expenses", representing the non-gas O&M expenses approved in Delta's last rate case, increased on a compounded annual basis by the CPI-U inflator. If the previous fiscal year's actual non-gas O&M expenses fall within $\pm$ 1.50% of the "performance-based" Indexed O&M Expense benchmark, then this actual non-gas O&M expense level will be used to compute the achieved ROE in establishing the AAF surcharge rate. If these same actual non-gas O&M expenses exceed the Indexed O&M Expense benchmark by more than 1.50%, then Delta would only be able to recognize 50% of this actual non-gas O&M expense excess for purposes of calculating the AAF. Conversely, if these same actual non-gas O&M expenses are lower than the Indexed O&M Expense benchmark by more than 1.50%, then Delta would be allowed to increase the actual expenses used to calculate the AAF by 50% of the amount by which the actual expenses are below 98.50% of the Indexed O&M Expense benchmark.

For any performance-based incentive benchmark to produce incremental ratepayer benefits over an existing situation under traditional regulation, the benchmark should be quite *challenging* and should *represent an improvement over what the utility was achieving previously.* It is only after "beating" such a challenging benchmark that any sharing of cost savings should accrue to the shareholders. This would be in keeping with the policy adopted by the KPSC in the three PBRs implemented in connecito with the gas supply recovery mechanisms of Western Kentucky Gas, Columbia Gas and LG&E. By contrast, Delta's proposed "Indexed O&M Expense" performance benchmark is not a challenging benchmark that incorporates improvements over prior performances. The "Indexed O&M Expense" performance benchmark is merely based on the Company's O&M expenses allowed in its most recent rate case, increased on an annual compounded basis by the CPI-U inflator. Specifically, under its proposed performance-based benchmark, the Company would be allowed to recover O&M expenses in the ARP that will be based on the actual level of O&M expenses from its last rate case, plus the cumulative annual compounded effect of an inflation multiplier, plus another 1.5 % above this inflated O&M level, plus 50 % of the excess O&M expenses over this 1.5%. This is not a challenging benchmark. It represents no improvement over what Delta was previously achieving. There is no incentive built into this benchmark for the Company to "beat" inflation or reduce its costs.

Q. DID THE COMPANY PERFORM A TEST BASED ON ACTUAL HISTORIC DATA WITH

REGARD TO THIS "INDEXED O&M EXPENSE" PERFORMANCE BENCHMARK?

A. Yes, the Company performed such a test in response to data request AG-59. In this data request, Delta was asked to assume that the O&M expenses per customer in 1993 would be the "base year" O&M expense level to which the annual CPI-U inflator for the years 1994, 1995, 1996, 1997 and 1998 would be applied in order to derive the Indexed O&M Expense per customer levels for these respective years. The Company then compared the actual per books O&M expense per customer levels for each of these years to the Indexed O&M Expense per customer levels for the corresponding years.

Q. WHAT WAS THE RESULT OF THIS TEST?

A. For the years 1995, 1996, 1997 and 1998, the Company's actual per books O&M expense per customer levels were significantly lower than the Indexed O&M Expense per customer levels. Pursuant to the Company's proposed incentive mechanism, Delta would be able to recognize as O&M expenses for purposes of establishing the AAF surcharge its actual O&M expenses plus 50% of the difference between the actual O&M expenses and 98.5% of the Indexed O&M expenses. Thus, if this performance-based cost control mechanism had been in effect during the most recent 5-year period 1993 through 1998, Delta would have been able to charge rates (through the AAF surcharge) that would have recovered a pro forma adjusted O&M expense level significantly higher than what its actual O&M expenses were during most of the 5-year period. The table below summarizes these results, taken from the Company's response to data request AG-59:

	AAF-Recoverable O&M Expenses Based on Indexed O&M Expense Cost Control Benchmark	Actual O&M Expenses	Excess O&M Exp. Recovery
1994	$8,209,117	$8,209,117	$ 0
1995	$8,266,680	$7,992,236	$ 274,444
1996	$8,870,453	$8,693,693	$ 176,760
1997	$9,202,226	$8,727,517	$ 474,709
1998	$9,333,211	$8,727,918	$ 605,293
			$1,531,206

As shown in the above table, the Company's actual accumulated O&M expenses during the 5-year period 1994-1998 are lower by approximately $1.5 million than the Company's proposed performance-based benchmark O&M expenses. From this test, one can draw the following conclusions:

(1) If the test results from this most recent 5-year period hold up for the near term future, then the pro forma adjusted O&M expenses the Company will be able to charge for purposes of establishing the AAF surcharge under its proposed performance-based cost control mechanism during the next 3-year experimental period will be significantly higher than the Company's actual O&M expenses for that 3-year period. This is clearly contrary to incentive ratemaking designed to control and/or reduce costs.

(2) The above-described test results clearly prove that the Company's proposed so-called "performance-based cost control" benchmark based on CPI-U indexed O&M expense levels is unrealistically easy to "beat", does not represent a challenging benchmark that requires improvements over prior performances, and does not provide the appropriate incentives for Delta to control and/or reduce its costs.

Q. WHAT ABOUT THE SECOND OF THE COMPANY'S PROPOSED PERFORMANCE-BASED COST CONTROLS?

A. Delta's second proposed performance benchmark, the 60% equity ratio limitation in the capital structure used to determine the Company's actual achieved rate of return for purposes of deriving the AAF surcharge, is almost twice as high as the current equity ratio, and is totally inappropriate to use as a performance benchmark in combination with the ROE range of 11.1% - 12.1% allowed by the PSC in the prior case. After all, this 11.1% - 12.1% ROE range allowed by the KPSC in Delta's last rate case was based on an equity ratio of approximately 36% and risk factors completely different from the risk factors inherent in the Company's proposed ARP. An increase in the equity ratio up to 60% would clearly have a significant downward impact on the Company's required ROE rate. These ratemaking aspects are discussed in much greater detail in the testimony of Dr. Weaver, the AG cost of capital witness in this case, who has concluded and recommended that it would be entirely inappropriate to use the Company's proposed ROE range of 11.1%-12.1% as part of its proposed ARP. For the aforementioned reasons, I fully agree with Dr. Weaver's conclusions and recommendations.

In addition, the response to data request AG-45 indicates that no studies have been performed by Delta or its consultants showing that an appropriate capital structure for Delta should contain 60% equity.

Q. MR. HENKES, DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

PRIOR REGULATORY EXPERIENCE OF
ROBERT J. HENKES

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987

Delmarva Power and Light Company Report Re. PROMOD and Its Use in Fuel Clause Proceedings*	Docket 85-26	10/1986
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990

Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

<u>GEORGIA</u>

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993

Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998

FERC

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

KENTUCKY

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997

Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982
Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982

Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

<u>NEW HAMPSHIRE</u>

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

<u>NEW JERSEY</u>

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978

Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1064	05/1985

Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993

Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding Purchased Power Contract Buy-Outs	Docket ER95090425	01/1996
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996

Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996
New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No. ER96030257	08/1996
Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No. EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No. ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No. ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No. ER97080567	12/1997

South Jersey Gas Company Limited Issue Rate Proceeding	Docket No. GR97050349	12/1997
New Jersey American Water Company Limited Issue Rate Proceeding	Docket No. WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lamberville Limited Issue Rate Proceedings	Docket Nos. WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No. WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No. WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No. ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No. WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding*	Docket No. WR99010032	07/1999

<u>NEW MEXICO</u>

Southwestern Public Service Company Electric Base Rate Proceeding*	Case 1957	11/1985
El Paso Electric Company Rate Moderation Plan	Case 2009	1986

El Paso Electric Company Electric Base Rate Proceeding	Case 2092	06/1987
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2162	06/1988
Public Service Company of New Mexico Phase-In Plan*	Case 2146/Phase II	10/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2279	11/1989
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2307	04/1990
El Paso Electric Company Rate Moderation Plan*	Case 2222	04/1990
Generic Electric Fuel Clause - New Mexico Amendments to NMPSC Rule 550	Case 2360	02/1991
Southwestern Public Service Company Rate Reduction Proceeding	Case 2573	03/1994
El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

OHIO

Dayton Power and Light Company Electric Base Rate Proceeding	Case 76-823	1976

PENNSYLVANIA

Duquesne Light Company Electric Base Rate Proceeding*	R.I.D. No. R-821945	09/1982
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	04/1984

AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	11/1984
National Fuel Gas Distribution Company Gas Base Rate Proceeding*	Docket R-870719	12/1987

RHODE ISLAND

Blackstone Valley Electric Company Electric Base Rate Proceeding	Docket No. 1289	
Newport Electric Company Report on Emergency Relief		

VERMONT

Continental Telephone Company of Vermont Base Rate Proceeding	Docket No. 3986	
Green Mountain Power Corporation Electric Base Rate Proceeding	Docket No. 5695	01/1994
Central Vermont Public Service Corp. Rate Investigation	Docket No. 5701	04/1994
Central Vermont Public Service Corp. Electric Base Rate Proceeding*	Docket No. 5724	05/1994
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5780	01/1995
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5857	01/1996

VIRGIN ISLANDS

Virgin Islands Telephone Corporation Base Rate Proceeding*	Docket 126	

* Testimonies prepared and submitted

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

Delta Natural Gas Company, Inc.	)	Case No. 99-046
Experimental Alternative Regulation Plan	)	

AFFIDAVIT

Comes the Affiant, Robert J. Henkes, and being duly sworn states as follows: The prepared Direct Testimony, together with supporting schedules, exhibits, and/or appendices attached thereto constitute the direct testimony of Affiant in the above styled case. Affiant further states that to the best of his information and belief, all statements made and matters contained therein are true and correct. Further Affiant saith not.

STATE OF CONNECTICUT
COUNTY OF Fairfield
Subscribed and sworn to before me by Robert J. Henkes this the 26th day of July, 1999.
MY COMMISSION EXPIRES: 12/31/03

Notary Public, State at Large

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

RECEIVED

JUL 30 1999

PUBLIC SERVICE
COMMISSION

In the Matter of	)	
DELTA NATURAL GAS COMPANY, INC.	)	CASE NO. 99-046
TO IMPLEMENT AN EXPERIMENTAL	)	
ALTERNATIVE REGULATION PLAN	)	

DIRECT TESTIMONY

OF

THOMAS S. CATLIN

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE

ATTORNEY GENERAL FOR THE COMMONWEALTH OF KENTUCKY

JULY 1999

EXETER

Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

TABLE OF CONTENTS

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

In the Matter of	)	
DELTA NATURAL GAS COMPANY, INC.	)	CASE NO. 99-046
TO IMPLEMENT AN EXPERIMENTAL	)	
ALTERNATIVE REGULATION PLAN	)	

DIRECT TESTIMONY OF THOMAS S. CATLIN

INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland 20904. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Master of Science Degree in Water Resources Engineering and Management from Arizona State University (1976). Major areas of study for this degree included pricing policy, economics, and management. I received my Bachelor of Science Degree in Physics and Math from the State University of New York at Stony Brook in 1974. I have also completed graduate courses in financial and management accounting.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From August 1976 until June 1977, I was employed by Arthur Beard Engineers in Phoenix, Arizona, where, among other responsibilities, I conducted economic feasibility, financial and implementation analyses in conjunction with utility construction projects. I also served as project engineer for two utility valuation studies.

From June 1977 until September 1981, I was employed by Camp Dresser & McKee, Inc. Prior to transferring to the Management Consulting Division of CDM in April 1978, I was involved in both project administration and design. My project administration responsibilities included budget preparation and labor and cost monitoring and forecasting. As a member of CDM's Management Consulting Division, I performed cost of service, rate, and financial studies on approximately 15 municipal and private water, wastewater and storm drainage utilities. These projects included: determining total costs of service; developing capital asset and depreciation bases; preparing cost allocation studies; evaluating alternative rate structures and designing rates; preparing bill analyses; developing cost and revenue projections; and preparing rate filings and expert testimony.

In September 1981, I accepted a position as a utility rates analyst with Exeter Associates, Inc. I became a principal and vice-president of the firm in 1984. Since joining Exeter, I have continued to be involved in the analysis of the operations of public utilities, with particular emphasis on utility rate regulation. I have been extensively involved in the review and analysis of utility rate filings, as well as other types of proceedings before state and federal regulatory authorities. My work in utility rate filings has focused on revenue requirements issues, but has also addressed service cost and rate design matters. I have also been involved in analyzing affiliate relations, alternative regulatory mechanisms, and regulatory restructuring issues. This experience has involved electric, water, and telephone utilities, as well as natural gas transmission and distribution companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony on more than 150 occasions before the Federal Energy Regulatory Commission and the public utility commissions of Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Idaho, Illinois, Indiana, Louisiana, Maine, Maryland, Montana, Nevada, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Utah, Virginia and West Virginia, as well as before this Commission. I have also filed rate case evidence by affidavit with the Connecticut Department of Public Utility Control.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member of the American Water Works Association (AWWA) and the Chesapeake Section of the AWWA. I currently serve on the AWWA's Rates and Charges Subcommittee and on the AWWA Water Utility Council's Technical Advisory Group on Economics.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Exeter Associates, Inc. was retained by the Office of Rate Intervention of the Attorney General (the Attorney General) to assist in the review and evaluation of the filing made by Delta Natural Gas Company (Delta or the Company) to implement an experimental alternative regulation plan. My testimony provides my analysis of the operation of the Company's proposed plan and its implications to the determination of the Company's rates. In addition, the Attorney General is presenting the testimony of Mr. Robert J. Henkes, who examines the claimed benefits of Delta's plan and compares Delta's plan to the rate plans of other utilities, and Dr. Carl G. K. Weaver who addresses rate of return issues associated with the Company's proposal.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In the remainder of my testimony, I provide an overview of Delta's proposed Alternative Regulation Plan and discuss my evaluation of that proposed plan. My testimony is organized according to topics. These topics are summarized in the table of contents for this testimony.

OVERVIEW OF DELTA'S PROPOSED PLAN

Q. WHAT REGULATORY CONCEPT IS DELTA PROPOSING IN THIS PROCEEDING?

A. Delta is proposing an Alternative Regulation Plan (ARP) that would replace the traditional regulatory procedures that have been utilized in the setting of Delta's prior and current rates. Traditional regulation focuses on a rate base which consists of individual components that are used and useful in the provision of service, and on reasonable, necessary and ongoing expenses including O&M, depreciation, taxes and return on investment. Under the proposed ARP, rates are initially adjusted annually on a prospective basis to recover Delta's budgeted costs. Subsequently, rates are adjusted on an after-the-fact basis to provide recovery of the Company's actual costs of service. The proposed ARP contains constraints that would limit the annual increase related to budgeted cost increases, and incentive features that would provide for sharing of benefits or costs under certain circumstances.

Q. PLEASE BRIEFLY EXPLAIN HOW DELTA'S PROPOSED ARP OPERATES SO AS TO AFFECT RATES.

A. Delta's ARP proposal basically consists of replacing traditional regulatory procedures with the application of three surcharge adjustment factors that would change rates on a formulaic basis. The first factor, to be effective on July 1 of each year, would adjust rates so they would produce revenues that would recover the fiscal year (July 1 - June 30) costs included in Delta's budget. Delta would compare the projected revenues it would receive from current rates to budgeted costs. If the projected revenues are too low to cover Delta's budgeted costs and produce a return on budgeted equity that is at the midpoint of the authorized return on equity range, then Delta would calculate a surcharge that would generate revenues consistent with budgeted costs and produce a rate of return at the mid-point of the authorized range. As proposed, this surcharge, the Annual Adjustment Component (AAC), would be calculated annually, filed with the Commission on June 1, and become effective on July 1.

A second surcharge, the Actual Adjustment Factor (AAF), looks back to the fiscal year just completed, and compares actual revenues and actual costs. Actual costs can exceed or fall short of budgeted costs for many reasons, just as actual revenues may exceed or fall short of budgeted revenues. If actual revenues and actual costs are sufficiently different to produce a return on equity that falls outside of the range of return, then an AAF would be calculated to bring in more or less revenue during the ensuing period to bring the historical return to the lower or upper rate of return range, respectively. Thus, the first factor, the AAC, operates so as to adjust rates consistent with Delta's budget, while the second factor, the AAF, operates so as to adjust rates to assure that actual fiscal results do, in fact, produce a return in the rate of return range. A third factor, the Balancing Adjustment Factor (BAF) adjusts rates each year for any over-or-under-collections over the past fiscal year from operation of the AAF or prior BAF.

The operation of the AAC and the AAF can be affected by several constraining and incentive features included in the proposed ARP. My subsequent testimony regarding my analysis of the Company's proposed ARP includes a discussion of the impact of the constraining and incentive features as they affect rate adjustments related to the operation of the proposed ARP.

Q. DO YOU BELIEVE THAT THE ALTERNATIVE REGULATION PLAN PROPOSED BY DELTA IS REASONABLE AND SHOULD BE ACCEPTED BY THE COMMISSION?

A. No, I do not. The Alternative Regulation Plan (ARP) proposed by the Company has several significant shortcomings which make the plan unacceptable as the basis for regulating the Company and setting rates. Of particular concern is the loss of incentive to control costs and the movement away from setting rates in a manner that ensures that only costs which are properly recovered from ratepayers are included in revenue requirements. In addition, I have identified an additional concern regarding the fact that Delta's proposed ARP would serve as a *de facto* weather normalization clause.

INCENTIVE TO CONTROL COSTS

Q. PLEASE ADDRESS THE ISSUE OF THE LOSS OF INCENTIVE TO CONTROL COSTS.

A. As a general matter, a rate mechanism which allows a utility to more or less automatically increase rates to recover cost increases will result in a reduction in the incentive for the utility to control costs. This is especially true for the ARP proposed by Delta.

Q. PLEASE EXPLAIN.

A. As described previously, under its proposed ARP, Delta will be allowed to adjust rates at the beginning of each year to recover its budgeted operating expenses and earn its allowed return on equity (currently 11.60 percent) on a prospective basis. After the end of each year, the Company will reconcile its actual revenues with its actual costs to ensure that it recovered those costs and earned its allowed return plus or minus 50 basis points. If it did not, it will then be allowed to implement a surcharge (or surcredit) to recover any underearnings (or flow back any overearnings) which occurred during that historical period. Accordingly, the Company's proposed procedure provides guaranteed recovery of the Company's costs. As a result, the incentive for Delta to control costs is significantly reduced or eliminated.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS WITH REGARD TO OPERATION OF DELTA'S PROPOSED AAC AND THE INCENTIVES WHICH IT CREATES?

A. Yes. Under the AAC, rates are set prospectively to recover budgeted costs and recover a return on equity equal to the midpoint of the range established by the Commission. Subsequently, actual revenues and costs are reconciled to ensure that the earned return on equity falls within the range established by the Commission (currently 11.1 percent to 12.1 percent). If the Company overspends its budget or earns below the lower threshold for other reasons, it is only allowed to implement a surcharge to recoup the amounts necessary to bring earnings back to 11.1 percent (or the low end of any new range set by the Commission). On the other hand, if the Company overearns, it is allowed to keep all amounts up to 12.1 percent (or the upper end of any new range). This proposed arrangement creates an incentive to under budget income and/or over budget costs so that the Company can earn more than the midpoint of the allowed range. That is, Delta can achieve a return above the midpoint of the allowed range if its actual operating results produce earnings greater than budgeted earnings. This clearly creates an incentive for the Company to be very conservative in preparing its budget by underestimating revenues and/or overbudgeting costs.

Q. DOES THE 5 PERCENT LIMIT ON ANNUAL RATE INCREASES WHICH DELTA HAS PROPOSED AS PART OF ITS PLAN CREATE AN INCENTIVE TO CONTROL COSTS?

A. No. Delta has proposed a limit of 5 percent per year in the overall increase in its rates which will be allowed under the Annual Adjustment Component (AAC) utilized to reflect budgeted operating results. However, this 5 percent ceiling or cap would apply to total revenues in the prior year, including both non-gas cost and gas cost revenues. Because any increase in gas costs would be separately accounted for and recovered through Delta's Gas Cost Recovery (GCR) mechanism, the full amount of the 5 percent increase in overall rates allowed at the beginning of each year will be available to offset budgeted increases in non-gas costs. Considering that purchased gas cost revenues represent some 45 to 50 percent of total revenue, this means that non-gas costs can increase by 9 to 10 percent per year without the increase in the AAC exceeding the allowable 5 percent ceiling. As a result, the 5 percent cap simply does not impose a meaningful limit which would create an incentive to control costs.

It must also be recognized that the 5 percent limit on the annual increase in the AAC used to reflect budgeted costs does not apply to the Actual

Adjustment Factor (AAF) used to reconcile actual costs and revenues. Therefore, even if Delta cannot increase the AAC by an amount sufficient to fully recover its projected cost increases because of the 5 percent limit, the proposed ARP would still allow the Company to recover any revenue shortfall through the AAF once those costs are actually incurred. As a result, any incentive to control costs which is created by the 5 percent limit on the increase in the AAC is largely, if not totally, superseded by the Company's ability to recoup any shortfalls through the AAF.

Q. IN ITS DIRECT TESTIMONY, DELTA AMENDED ITS ORIGINAL PROPOSAL TO INCLUDE WHAT IT REFERS TO AS PERFORMANCE-BASED CONTROLS. PLEASE PROVIDE AN OVERVIEW OF THOSE PROPOSED CONTROLS.

A. As indicated previously, the Company has proposed to establish two performance-based controls as part of its ARP. First, Delta has proposed to establish a mechanism under which its non-gas O&M expenses per customer in each year of the plan would be compared to an indexed allowance based on the O&M per customer approved in the Company's last rate case. This indexed allowance would be equal to the O&M per customer in the most recent rate case times the increase in the Consumer Price Index for Urban Consumers (CPI-U) since that case. If actual non-gas O&M expenses per customer fall within a range of ± 1.50 percent of the indexed allowance, actual O&M expense would be used in calculating the AAF. If actual expenses were less than the indexed amount minus 1.5 percent, Delta would be allowed to retain 50 percent of the amount below this lower threshold. Conversely, if actual O&M costs exceed the indexed amount plus 1.5 percent, Delta is only allowed to recover one-half of the amount in excess of this upper threshold.

The second change in original ARP which Delta has identified as a performance-based control is to place a limit on the amount of common equity which can be included in total capitalization for purposes of computing the AAF. Delta has proposed to set the limit on the equity percentage of capitalization at 60 percent.

Q. DO YOU AGREE WITH THE COMPANY THAT THE PROPOSED O&M EXPENSE CONTROL WILL PROVIDE A PROVIDE A STRONG INCENTIVE TO CONTROL COSTS?

A. No. Like the 5 percent limit on revenue increases under the AAC, the Company's proposed O&M mechanism is not likely to impose any real limitation on the increases in O&M costs which can be passed through to ratepayers. Actual data demonstrate that not only are Delta's O&M costs increasing at a rate less than inflation, but Delta's O&M costs on a per customer basis are declining. Over the five fiscal years from 1993 through 1998, Delta's non-gas O&M costs have increased at an annual rate of 2.28 percent. Over the same time period, inflation as measured by the CPI-U has averaged a higher 2.44 percent year. More importantly, non-gas costs as measured on a per customer basis have <u>declined</u> at the rate of 0.48 percent per year over the same time period. Hence, the Company's proposal to limit the increase in O&M expenses per customer which can be passed through to customers to the rate of inflation (plus an additional 1.5 percent) is not an effective limit and does not create a true incentive to control costs.

Q. IS IT REASONABLE TO EXPECT THAT THE COMPANY'S NON-GAS O&M EXPENSES AS MEASURED ON A PER CUSTOMER BASIS WOULD GROW AT A RATE LESS THE RATE OF INFLATION AS MEASURED BY THE CPI-U?

A. Yes, It is reasonable to expect that Delta's non-gas O&M costs per customer would grow at a rate less than the growth in the CPI-U for several reasons. First, non-gas O&M expenses are, for the most part, not customer sensitive. That is, growth in the number of customers from year to year is not likely to have any significant impact on non-gas O&M expenses. Therefore, one would expect non-gas O&M expenses per customer to decline over time absent inflation, thereby causing the overall growth rate to be less than inflation.

Second, a growth rate in expenses per customer less than the rate of inflation is consistent with the fact that Delta is likely to be realizing productivity gains. These productivity gains can be expected to occur due in part to customer and sales growth and due in part to improved operations.

Third, it is reasonable to expect that growth in Delta's expenses would be less than the rate of inflation as measured by the CPI-U itself because the CPI-U is likely to overstate the effect of price increases on Delta's expenses. The CPI-U is heavily weighted toward consumer items, such as food/beverages, housing, apparel, transportation and recreation. Because it is a measure of price increases to ultimate consumers, the percentage increase in the CPI-U is consistently higher than the percentage increase in broader measures of inflation such as the Gross Domestic Product-Price Index (GDP-PI). The GDP-PI is a measure change prices of all final goods and services produced in a given year, and as such, is likely to be more representative of the price increases which Delta experiences than the CPI-U.

Q. DOES DELTA'S PROPOSED O&M MECHANISM REPRESENT AN APPROPRIATE PERFORMANCE-BASED CONTROL?

A. No. A performance-based control should be designed to reward performance which is better than has historically been achieved without the performance mechanism in place (or penalize performance which is worse than historically achieved). Delta's plan does not work in this manner. Under Delta's proposed plan, Delta would be able to earn additional profits as long as non-gas O&M costs per customer simply continue to grow, as they have historically, at a rate less than inflation. In fact, the Company could perform much worse than it has historically and still realize additional profits under its proposed mechanism. For example, over the five-year period from 1993 through 1998, Delta's non-gas O&M cost per customer changed at a rate 2.92 percent less than the rate of inflation as measured by the CPI-U. Under its proposed mechanism, Delta will realize additional profits over the three-year trial period as long as non-gas O&M costs grow at any rate below 0.50 percent less than the rate of inflation.

Q. WHAT ADDITIONAL PROFITS WOULD DELTA HAVE RECEIVED DURING THE HISTORICAL PERIOD TO WHICH YOU HAVE REFERRED HAD ITS PROPOSED O&M MECHANISM BEEN IN PLACE?

A. In response to AG-59, Delta provided an analysis showing the results its proposed mechanism would have produced had it been in place during 1994 through 1998 and using 1993 as the basis for establishing the base O&M costs per customer. This analysis shows that in 1994, O&M costs would have been within 1.5 percent of the index amount calculated by adjusting 1993 costs for inflation. In each of the subsequent years 1995 through 1998, the actual O&M expenses per customer would have been more than 1.5 percent below the index amount.

In total over those four years, under its proposed mechanism, Delta would have recovered $765,603 more in O&M costs than it actually incurred. Thus, Delta's plan rewards the Company with additional revenues not because of incentives to reduce costs, but simply by matching actual cost experience under traditional regulation.

Q. WHAT COMMENTS DO YOU HAVE WITH REGARD TO DELTA'S PROPOSAL FOR A SECOND PERFORMANCE CONTROL BASED ON THE EQUITY PERCENTAGE OF CAPITALIZATION?

A. As its second performance control, Delta has proposed to limit the balance of common equity which it can use in calculating its revenue requirements to no more than 60 percent of total capitalization. In comparison, the equity component of capitalization which the Commission approved in Delta's last rate case in Case No. 97-066 was 36.25 percent. Moreover, according to the responses to AG-35 and PSC-44, the Company's equity ratio remains at or below 35 percent currently. Therefore, Delta's proposal to limit its equity ratio to 60 percent for purposes of setting rates will have no significance for the foreseeable future. Accordingly, this proposal, like the proposal to limit O&M expenses, does not qualify as a performance-based control.

DETERMINATION OF ELIGIBLE COSTS

Q. PLEASE ADDRESS THE ISSUE OF MOVING AWAY FROM SETTING RATES IN A MANNER WHICH ENSURES THAT ONLY COSTS THAT ARE PROPERLY RECOVERED FROM RATEPAYERS ARE INCLUDED IN REVENUE REQUIREMENTS.

A. Under Delta's proposed alternative regulatory framework, rates will no longer be established to allow the Company to earn a return on its Commission established rate base. There will no longer be any review made to establish the net plant in service and other assets devoted to providing public utility service on which the Company is entitled to earn a return. Instead, rates will be established to allow the Company to recover its per books interest expense and to earn a specified rate of return on the book balance of equity. Under the Company's proposed procedures, Delta would earn a return on all capital, including capital which may not be eligible to earn a return under traditional rate base regulation. For example, the Company's balance sheet includes assets such as a note receivable from an officer, the cash surrender value of officers' life insurance, and accumulated deferred income tax asset balances which are not included in rate base. However, unless capitalization is explicitly adjusted to remove these items, the Company would receive a return on capital for these items under its proposed procedure.

The movement away from setting rates to only include costs properly recovered from ratepayers also occurs on the operating expense/net income side of the Company's proposed plan. Under the Company's proposal, rates are initially established on the basis of budgeted operating costs and subsequently "trued up" based on earned net income. As proposed, there is no provision for adjusting either the budget or actual net income to exclude costs disallowed by the Commission.[1] In addition, items such as income taxes may differ on a per books basis from what is allowable for ratemaking. Finally, the proposed procedures for establishing rates based on a budget and truing up actual results based on earned net income would make it extremely difficult to

[1]Examples of disallowed expenses would include contributions and donations, promotional and institutional advertising, miscellaneous expenses, and the forgiven loan payment from an officer.

thoroughly evaluate the reasonableness of the costs included for recovery in rates.

Q. IS DELTA'S ARP PROPOSAL BASED ON ANY CLAIM THAT TRADITIONAL REGULATION HAS BECOME AN UNREASONABLE REGULATORY MODEL?

A. No. In response to AG-60, Delta had stated that traditional regulation is consistent with regulatory practice in Kentucky and that it continues to be a reasonable method for setting rates.

Q. HAS DELTA PROPOSED ITS ARP AS A COMPLETE SUBSTITUTE FOR TRADITIONAL REGULATION?

A. No. On the one hand, Delta proposes to have its rates determined on the basis of the ARP mechanism during a three-year trial period. In that way, it appears that Delta views the ARP as a substitute for traditional regulation. On the other hand, however, Delta reserves the right to file a general rate case during the trial period. In this regard, the ARP is not a substitute for traditional regulation. Under its proposal, Delta can pick and choose to its own advantage whether its rates are determined under operation of its proposed ARP, or under traditional regulatory procedures during the effective period of the ARP. Delta should not have the selective right to choose whichever regulatory scheme is most advantageous to the Company during any ARP trial period.

WEATHER NORMALIZATION

Q. ON A YEARLY BASIS, WHAT IS TYPICALLY THE MAJOR REASON FOR A GAS DISTRIBUTION UTILITY'S EARNINGS TO VARY?

A. A gas distribution company's yearly earnings are subject to significant variation due to changes in sales, or throughput in general. Non-gas related costs are typically collected largely on a volumetric basis. The colder the weather, the greater the throughput and the greater the revenues. Similarly, the warmer the weather, the lesser the throughput and revenues. Combined with significant fixed costs, greater or lesser revenues translate into greater or lesser earnings. Over the long run, normal weather is expected. In any given year, however, weather related throughput variances can significantly impact earnings.

Q. WOULD DELTA'S PROPOSED ARP LEAD TO AN ADJUSTMENT IN RATES BECAUSE OF THE IMPACT THAT VARYING WEATHER WOULD HAVE ON REVENUES AND EARNINGS?

A. Yes, the proposed ARP would consider all variations in revenues and costs regardless of their cause. Probably the single most significant cause of differences between budgeted earnings for a given year and actual achieved earnings is the impact of weather on sales and other throughput, and hence, on earnings. Because the proposed ARP considers the impact of all events that affect revenues, costs and earnings in the determination of its adjustment factors, the proposed ARP also serves as a weather normalization adjustment ("WNA") clause. That is, both a WNA clause and the proposed ARP would increase rates in an ensuing period when weather in the prior period was warmer than normal, or decrease rates after a period of colder than normal weather. The two clauses may appropriately be viewed as substitute mechanisms addressing typically the largest single reason why forecast earnings may not be realized for a gas distribution company such as Delta. Delta has included a request for a WNA in the tariff changes it has proposed in its currently on-going general rate case, Case No. 99-070.

Q. ARE THERE ISSUES THAT NEED TO BE ADDRESSED BEFORE ADOPTING A WEATHER NORMALIZATION ADJUSTMENT PROCEDURE?

A. Yes, there are important matters to be evaluated when considering whether a WNA mechanism that may be authorized by the Commission is structured so as to be in the public interest. While yearly weather fluctuates from normal, in the long run normal weather is expected. Since, over the long haul, revenues will reflect normal weather, this leads to the fundamental question of whether rates should be adjusted annually consistent with the assumption that every year's weather is normal. The existence of a WNA mechanism necessarily creates some significant problems from the ratepayer's perspective. Consider a warm year that is followed by a cold year. The warm year will reduce revenues, requiring a positive WNA factor to be applied in the succeeding period. However, the succeeding period is colder than normal. The result is that in the succeeding period, ratepayers would not only be facing high bills because of their increased gas usage, but also because of the WNA rate surcharge. The Commission should fully analyze the rationale for a WNA as part of any approval process. Delta's ARP proposal would have the Commission approve *de facto* a WNA process, subsumed within its ARP, without directly considering whether such a mechanism is in the public interest.

Other important technical issues related to WNA clauses should also be presented to the Commission as part of any request for automatic rate adjustments related to the vagaries of weather. The definition of normal weather, the determination of the portion of gas usage that is weather-related, the consistency of normal weather included in base rate determinations and in the WNA clause, the consistency of normal weather determination over time and the statistical and methodological bases of making these determinations are all examples of the kinds of issues and concerns that need to be examined and presented to the Commission in the consideration of any proposal to adjust revenues to comport with revenues associated with normal weather. By including a *de facto* WNA within its ARP, Delta precludes any discussion of the myriad potential issues that should be examined as part of a reasonable WNA approval process.

Q. WHAT DO YOU RECOMMEND?

A. The WNA included in the proposed ARP should be dealt with separately and not subsumed within an ARP. Delta's request for a WNA clause in its current general rate case provides this opportunity.

CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE ALTERNATIVE REGULATION PLAN PROPOSED BY DELTA.

A. For the reasons discussed in detail previously in my testimony, I believe that the Company's ARP, as proposed, is not reasonable and is not an appropriate substitute for traditional rate base/rate of return regulation. In addition, because of the fundamental flaws in the Company's proposed plan, that plan cannot readily be modified in the context of this proceeding to make it a workable alternative to traditional regulation. Therefore, I am recommending that the Commission reject the Company's proposal to implement an alternative regulatory mechanism at this time.

Q. IF THE COMMISSION WISHES TO GIVE FURTHER CONSIDERATION TO AN ALTERNATIVE REGULATORY PLAN FOR DELTA IN THE FUTURE, DO YOU HAVE ANY RECOMMENDATIONS?

A. Yes. If the Commission wishes to give further consideration to an alternative regulatory plan for Delta in a future proceeding, I believe that the Commission should require Delta to file a plan which includes several key aspects. The features or attributes which I would recommend the Commission establish are described below.

- Rate adjustments should be based on achieved results, not on budget estimates in order to avoid the various problems discussed in my testimony.

- Achieved earnings and, in turn, any rate adjustments should be measured on a "Commission basis." That is, rate base, revenues, expenses and taxes should be determined in a manner consistent with the Commission's order in the Company's most recent rate case.

- In determining achieved earnings, revenues and the associated purchased gas costs should be weather normalized. The decision to implement a weather normalization clause should be based on the separate consideration of the issues involved. A *de facto* weather normalization clause should not be incorporated in an alternative regulatory mechanism.

- When the Company's return falls outside the authorized range, adjustments in rates under an alternative regulatory mechanism should be made to bring the return to the upper or lower end of the band depending on whether Delta is overearning or underearning, respectively.

- Some limitations on the cost increases which can be flowed through to ratepayers should be established to ensure that the alternative regulatory mechanism does not fully eliminate the incentives to control costs. An example of such a mechanism might be a limit that the increase in O&M costs per customer will be no greater than that which has occurred historically.

- As explained by AG Witness Weaver, implementation of an alternative regulatory mechanism will increase the stability of Delta's earnings, thereby reducing one aspect of risk for the Company and, in turn, its cost of capital. This reduction in the cost of capital should be recognized at the time any alternative regulatory plan is adopted.

- The Commission should establish what it believes is a reasonable limit on the equity component of capitalization.

- The mechanism should be implemented for a trial period of no more than three years. At the end of the trial period, an evaluation can be made as to whether it is appropriate to continue the existing mechanism and/or whether any changes should be made.

- At the end of the three-year trial period and approximately each three years thereafter if the plan is continued, a review of Delta's rates should be made to ensure that only costs properly recovered from ratepayers are being included in the cost of service.

- During the three-year trial period and, if the mechanism is continued thereafter, during subsequent intervals between rate reviews, a "stay-out" provision should be included. Under the provision, Delta would not be allowed to file a general rate case except under force majeure conditions.

- A reasonable period must be established to allow the review of the annual filings by the Commission Staff, the Attorney General and any other applicable parties.

Q, DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

In the Matter of	)	
DELTA NATURAL GAS COMPANY, INC.	)	CASE NO. 99-046
TO IMPLEMENT AN EXPERIMENTAL	)	
ALTERNATIVE REGULATION PLAN	)	

Affidavit of

Thomas S. Catlin

I, Thomas S. Catlin, hereby certify that the statements contained in the foregoing testimony are true and correct to the best of my knowledge, information, and belief.

Thomas S. Catlin

Thomas S. Catlin

STATE OF MARYLAND	)	
	)	SS
COUNTY OF MONTGOMERY	)	

Subscribed and sworn to before me, this 29th day of July 1999.

Cheryl Lunsford

Notary Public

Commission Expires 8/13/02

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
JUL 30 1999
PUBLIC SERVICE
COMMISSION

In the Matter of:

Delta Natural Gas Company, Inc.	)	
Experimental Alternative	)	Case No. 99-046
Regulation Plan	)	

TESTIMONY OF CARL G.K. WEAVER
APPEARING ON BEHALF OF THE OFFICE OF
THE ATTORNEY GENERAL FOR THE COMMONWEALTH OF KENTUCKY
UTILITY AND RATE INTERVENTION DIVISION

July 30, 1999

BEFORE THE
PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY

Testimony of
Carl G. K. Weaver
in the Matter of:

Experimental Alternative Regulation Plan
Delta Natural Gas Co., Inc.

Case No. 99-046

Q. Please state your name, address and occupation.

A. My name is Carl Weaver. My address is 4713 Wengers Mill Road, Linville, Virginia 22834. I am an emeritus professor of finance at James Madison University.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the results the results of a study of Delta Natural Gas Co., Inc. (Delta's) cost of equity capital that will result if the proposed ARP is adopted. In addition, I will discuss the reduction in the common equity risk premium that would result from the implementation of the "Experimental Alternative Regulation Plan" (ARP) proposed by Delta. I will also examine the second performance-based control proposed by Delta. This control is the limitation that equity be limited to no more than 60% of total capitalization.

Q. Have you provided a description of your qualifications to perform these tasks?

A. Yes. It is included as Appendix I of this testimony.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. It was prepared by me, and it is included as a part of this testimony.

Q. Before you proceed with the cost of equity analysis, what do you conclude about the equity capital limitation at 60%?

A. This proposal flies in the face of sound financial decision making regarding the use of leverage. Revenue variability and the amount of leverage used have an inverse relationship. The stabilization of revenues and earnings will allow a greater use of leverage without disproportionately increasing risk. The greater the variability in revenues, the smaller the amount of leverage that should be used because leverage magnifies the variability in earnings per share that results from a given amount of variability in revenues.

Q. What do you recommend with respect to the 60% equity limitation as an ARP performance-based control?

A. I recommend that this performance-based control not be adopted. The amount of leverage employed for financing assets is an internal management decision. When setting rates, the Commission could use a hypothetical capital structure if it finds that the capital structure chosen by management has excessive equity capital. If the capital structure equity limitation is to be used, it should be set close to the current level of equity that is in the capital structure.

Q. Dr. Weaver, you stated that the ARP proposed by Delta will reduce the risk embedded in its outstanding common stock. How does the ARP cause a risk reduction?

A. As I have indicated on page 3 of Appendix II, risk is the likelihood that the actual return to an equity investor after the passage of time may be less than the return that was expected when the investment decision was made. A source of risk is *any* phenomenon which may cause the actual future return to be less than the anticipated future return. The ARP will reduce the likelihood that a future return is lower. In fact, Delta acknowledges on page 10 of the February 5 letter to the Commission near the beginning of Section 5.1, Overview of the Proposed Mechanism in which the ARP is described that:

> The primary objective of the proposed mechanism is to establish a process for ensuring that the utility's rate of return falls within the range found to be fair, just and reasonable by the Commission."

The ARP, as proposed and if adopted, will reduce risk by (1) initially establishing rates that covers budgeted expenses and provides a return on budgeted equity equal to the return found by the PSC to be fair and reasonable; (2) then these initial rates are adjusted after a year of operation by a make-whole true-up factor so that the actual return on equity will fall within a 50 basis point range of the cost of equity; and (3) then a further true-up is performed by a balancing factor to assure that the return on equity is earned within 50 basis points of the return allowed.

Risk, the likelihood that the return is less than the return expected, is reduced to the potential for a delay in earning the rate of return and the 50 basis point band around the authorized return.

Q. Are there other instances in the presentation or testimony that indicates that Delta agrees that the purpose of the ARP is to reduce risk to common stock investors?

A. Yes. Company Witness Seelye, in his direct testimony on page 4 at line 15 states that "the primary objective of the proposed mechanism is to establish a process ... for ensuring that

Delta's rate of return falls within the range found to be fair, just and reasonable by the Commission." Further elaboration on this is provided by Witness Seelye in his response to question 18 of the PSC Data Request dated June 4, 1989 which asked about the effect of the ARP on financial and operating performance. He answers that, "the proposed mechanism will significantly reduce the variability experienced in Delta's earnings and help prevent financial harm that could result from such variability." On page 3 of the February 5 letter to the Commission in Section 1.0 of the Background and Purpose of Filing it is stated:

> Accordingly, our goal with this filing is to establish an orderly and expeditious process for automatically making rate adjustments to keep the Delta's rate of return within the range authorized by the Commission.

The first benefit in the list of benefits provided in the February 5 letter is:

> The proposed alternative rate making mechanism would ensure that Delta's rate of return falls within the range authorized by the Commission.

Q. How does reduced risk effect the cost of equity?

A. A reduction in Delta's risk will lower its cost of equity because a smaller risk premium will be embodied in the equity cost rate.

Q. How do you determine a cost of equity for Delta since it has proposed an ARP but the ARP has not been adopted?

A. I first performed a study of the cost of equity with the assumption that Delta is regulated using the return on rate base method that is presently used by the Commission. Next, I performed a study of the equity risk premium and estimate the extent by which the risk premium will be reduced by the ARP. Then I adjust the cost of equity by the reduction in the risk premium assuming that the ARP is adopted.

Q. Are you recommending that the ARP be adopted?

A. No. I am determining the cost of equity that would be fair and reasonable if the Commission were to decide to adopt the ARP. This recommendation would not apply if the ARP is not adopted.

Q. Dr. Weaver, before you begin your analysis of the cost of equity, would you please explain the concept of the cost of capital and the methods you used to determine the cost of equity.

A. The concepts of the cost of capital; risk, as it relates to the capital market; and the methods for determining the cost of equity are discussed in Appendix II of this testimony.

Q. What economic principles are mandated for determining the cost of capital for regulated utilities?

A. The economic principles for determining the cost of capital for regulated utilities have been set forth in the Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923), and F.P.C. v. Hope Natural Gas Co., 302 U.S. 591 (1944), Supreme Court decisions. The Court, in the Bluefield case stated:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In the Hope case the Court stated:

> . . . It is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . . By that standard, the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

These principles have been confirmed in Permian Basin Area Rate Cases, 390 U.S. 747 (1968) and Federal Power Comm. v. Memphis Light Gas & Water Division, 411 U.S. 458 (1973).

Q. Dr. Weaver, how do you interpret these economic principles?

A. From a financial perspective, these U.S. Supreme Court decisions set forth three interrelated criteria that a regulatory determined rate of return should meet. First, the return should be comparable to the return that is earned by other companies that have similar risk. Second, the return should enable the regulated utility to obtain funds from the capital market at a cost commensurate with its risk. Third, the return should be sufficient to preserve the financial integrity of the company.

Q. How do your findings assure compliance with your interpretation of those economic principals?

A. I have selected methods for determining the cost of equity that rely on the "opportunity cost principal." This assures compliance with my interpretation of the requirements of Bluefield and Hope.

Q. What is the opportunity cost principal?

A. The opportunity cost principal is the premise that, in the capital market, investors have numerous alternatives in which to invest. It recognizes that investors either directly or indirectly consider the prospective risk and return opportunities that are available from each investment alternative. Investors, after comparing their alternative investment opportunities, will choose those investments which are expected to have the highest level of expected return for a given level of potential

Q. How does the opportunity cost principle work to assure that the cost of equity meets the comparable earnings, capital attraction and financial integrity principals that you described?

A. The first Bluefield and Hope mandate requires that the regulated company's return be comparable to the return earned by other companies that have similar risk. In the capital market, investors continuously compare the expected returns and risks of investment alternatives to make their purchase and sell decisions. The purchase and sell decisions effect the supply and demand for securities, which, in turn, causes stock prices to rise or fall. As a result, stock prices reflect the return and risk expectations of a single investment opportunity relative to all other investment opportunities that exist in the capital market. Comparability of earnings automatically occurs from the use of cost of equity determination models that are implemented with stock price data.

The financial integrity mandate is also met by using capital market data. If a firm's return was so low that it could not pay its expenses when due, it would be more risky, and investors would not purchase that company's stock. Its stock price would fall, with all other factors remaining the same, causing its cost of capital to be considerably higher than the cost of capital for other firms. In regulation, the increased cost of capital would result in a higher return and higher rates. This would increase revenues and improve the regulated company's financial integrity. Once again, the use of stock price data from both the individual company and a group companies in a cost of equity determination model assures that financial integrity will be maintained.

The opportunity cost principle also results in meeting the capital attraction mandate. In the capital market, each firm is in competition with other firms to obtain capital at the lowest cost. Since the cost of equity rate is determined from the price that investors have been shown to be willing to pay for a security, it reflects the capital market's cost rate for attracting capital.

For these reasons, the use of capital market price data in the analysis causes the results to be in compliance with the Bluefield and Hope mandates that the return (1) be comparable to the return earned by other firms with similar risk, (2) preserve the firm's financial integrity, and (3) enable it to attract capital.

Q. Dr. Weaver, you indicated that you first performed an analysis of the cost of equity that would result if the proposed ARP is not adopted. What cost of equity determination methods did you use in this analysis?

A. I used the discounted cash flow (DCF) technique, the Capital Asset Pricing Model

(CAPM), and the bond-yield-plus-risk-premium approach (bond-risk-premium). As I previously indicated, the cost of equity is determined by investors making buy and sell decisions in the overall capital market. The DCF, CAPM, and bond-risk-premium methods provide information about what investors think the cost of equity should be for a particular company relative to the risk and return expected to be earned by each of the financial assets traded in the capital market.

The use of these methods, all implemented with data taken from the capital market for companies that are similar to Delta, assures that the cost of equity determined for Delta will be comparable to the cost of equity for other firms that have similar risk and meet the comparable earnings, capital attraction, and financial integrity requirements.

Q. What capital market data does the DCF method use to conform to the opportunity cost principle?

A. The DCF method incorporates stock prices by requiring the dividend yield as one of the two components of the model. The dividend yield is determined from stock price data taken from the capital market. It is calculated as the expected dividend amount divided by the stock price.

Q. You indicated that you use the CAPM. What capital market data does that require?

A. All of the data used by the CAPM comes from the capital market. The model's measurement starts with the risk-free interest rate that is observed in the capital market. The interest rate on government bonds or bills is usually used as a proxy for this rate. An equity risk-premium is added to the risk-free rate. This premium is determined as the average risk premium charged by equity securities in the capital market. This average premium is then adjusted so that it reflects the risk-premium of the specific company's being evaluated. This is done by multiplying the market risk premium by Beta. The specific company's equity risk-premium, when added to the risk-free rate, indicates the cost of equity.

The CAPM, by using all capital market data causes it to fully comply with the opportunity cost principal.

Q. Please explain how the bond-risk-premium method complies with the opportunity cost principal.

A. The bond-risk-premium method is an *ad-hoc* procedure used to estimate the cost of equity by adding an equity risk premium to an interest rate. The interest rate is directly observed in the capital market. The equity risk-premium is sometimes a subjective guess about what it might be. However, I measure the risk premium by subtracting the actual equity returns earned by the companies that are similar to Delta from long-term Treasury bonds. This provides an actual risk premium that can be added to current and forecasted long-term Treasury bond rates. As a result, the cost of equity provided by this method also complies with the opportunity cost principal.

Q. What steps did you take in your cost of equity analysis?

I selected a group of five gas distribution companies that have common stock traded in the capital market. These were used to supplement the data observed for Delta and allow for greater breadth and depth of capital market interactions in the findings. Delta's common stock is traded in the over-the-counter market and the use of the five companies' data helps confirm the findings of companies that have comparable risk.

In the selection process, I examined the risk measures for the companies and, where possible, compared the risk of these companies to the risk of Delta. The measures that were used to select similar companies were total asset size, the rate of increase in total assets in 1998, net sales to total assets, the common equity ratio, and total liabilities to total assets. debt to equity ratios, and sales to fixed asset data. Other ratios that I examined when I compared the risk of Delta with the risk of the five companies were the capital structure ratios, cash flow ratios, Standard and Poor's risk assessment measures, and Value Line assessment measures.

I next examined the trend in forecasted interest rates, economic growth, and inflation to assess economic conditions. This data provides information about whether capital cost rates are expected to be rising, falling, or remain stable. It also provides information about business conditions and risk.

After I assessed economic conditions, I used capital market data for the five gas distribution companies to implement the three cost of equity models. I performed sensitivity analysis by implementing each model using different data and different assumptions to provide additional information about the risk and return expectations of different investors. I used the information provided by the cost of equity models and the sensitivity analysis to augment my judgement about Delta's cost of equity, assuming that current regulatory methods are used.

Finally, I assessed the amount of risk reduction that would result from the implementation of the ARP and I applied this risk reduction to the cost of equity for Delta that I found in the previous steps to determine my recommendation for the cost of equity for Delta.

Selection of Companies and Risk Analysis

Q. Dr. Weaver, you indicated that you selected a group of gas distribution companies to use to obtain data for your analysis. Why did you do that?

A. Data from other gas distribution companies was used to provide information for estimating the cost of equity. In the final analysis, judgement is required. Since the companies have similarities to Delta, this information is useful for augmenting that judgement. Furthermore, the additional data assures that the recommendation will meet the comparability test that is required by Bluefield and Hope.

Q. Do the companies that you selected have common stock that is traded in the same market as Delta?

A. No. Delta's common stock is traded in the over-the-counter (OTC) market and it is listed on the National Association of Securities Dealers Automated Quotation (NASDAQ) National Market System. Its stock prices are reported in the Wall Street Journal and other financial publications. Financial information about Delta is included in Standard and Poor's Stock Reports.

The five companies that were selected are listed on the New York Stock Exchange. Studies have confirmed that the New York Stock Exchange (NYSE) is an efficient market where stock prices reflect value. In this market, investors constantly compare information about earnings prospects and risk for different companies when making their stock purchase or sell decisions.

Q. What companies did you select for the analysis?

A. The companies that I selected are: Cascade Natural Gas Corporation; Connecticut Energy Corporation; CTG Resources, Inc.; Energen Corporation; and South Jersey Industries, Inc.

Q. What steps did you use to select the five companies?

A. The selection criteria for these companies is shown in Schedules 1 - 4 of my Exhibit and summarized on Schedule 5. I started with the twenty three investor owned gas distribution companies that are listed in Value Line. I reduced the number of companies in three steps.

1st- I selected companies whose dollar value of total assets in 1998 was less than $1 billion. There were ten companies that met this criteria. These companies are shown on Schedule 1 of my Exhibit.

2d- I eliminated Providence Energy Corp. and NUI Corp. because these companies reduced the dollar amount of total assets from 1997 to 1998 and did not have a similar external financing pressure as Delta did.

3d- I selected companies that require an investment in total assets for providing service that is more nearly similar to Delta. The net sales to total assets ratio shows the number of dollars invested in assets per dollar of sales. Rural companies would typically require a higher investment in assets per customer than urban companies. Delta's ratio was 0.44. I used a maximum 0.70 ratio of the 1996-98 average net sales to total assets for this measure. This caused Indiana Energy, Laclede, New Jersey Resources to be eliminated. Schedule 2 shows the average net sales to total assets ratios for the 23 gas distribution companies listed in Value Line. The remaining companies were Cascade, CTG Resources, Connecticut Energy, Energen, and South Jersey Industries.

Q. Did you consider other measures in the selection process?

A. Yes. I examined the financial leverage of the companies listed in Value Line.. Leverage, measured by the mix of debt and equity capital, is a source of risk to companies. Financial risk results from two sources: (1) the fixed interest charges and principal repayment provisions associated with debt that, contractually, must be paid or the company would be in default and (2) the increase in the variability of earnings per share that is caused by leverage.

Q. Why is variability of earnings per share a source of risk?

A. Return expectations are more difficult to estimate when a greater variability of earnings per share exists. In addition, when there is greater variability of earnings per share, there is a greater likelihood that, in any given year, earnings per share will be lower than expected.

Q. What measures of leverage did you examine?

A. I looked at two measures of leverage. The first is the common equity ratio and the other was total liabilities to total assets. The common equity ratio is the percent of common equity to total capitalization. It represents long-term or permanent financing sources. Total liabilities to total assets provides a measure of the use of both long-term and short-term financing. These measures for the 23 companies listed by Value Line are shown in Schedules 3 and 4.

Q. Please summarize the selection measures for the five companies.

A. Schedule 5 provides a summary of the selection measures. The measures for Delta are shown on the bottom line of that schedule.

In 1998, Delta had $103 million in total assets and the selected companies averaged $594 million in total assets. The five companies are small relative to the other 13 companies reported by Value Line. The thirteen companies average $1,973 million in total assets. This means that the five companies are more risky than the other companies listed by Value Line. However, the five companies are larger than Delta and less risky, to the extent that size effects risk. A larger size company has greater customer diversity and financing flexibility.

The 1997-98 increase in total assets was 3.2% for the five companies and 3.1% for Delta. The relative financing needs for increasing the amount of assets was about the same for the five companies and for Delta.

For the five companies, the 1996-98 average net sales was $0.59 per dollar invested in assets versus $0.44 for Delta. Delta, being located in a rural and largely mountainous region requires a greater investment in assets to provide service. However, on a relative basis, the five companies selected have an investment closer to Delta than the other companies listed by Value Line. The companies with a ratio above $0.70 that were not chosen averaged $0.81 in assets per dollar of sales.

Q. How do the companies compare with respect to leverage?

A. The five companies have less leverage than Delta. Delta's common equity ratio is 38.5% compared to 49.2% for the five companies. The average total liabilities to total assets ratio for Delta is also greater but on a relative basis, the five companies have a greater amount of current liabilities than Delta. This indicates that the companies have more immediate repayment obligations than Delta and this mitigates the difference in the financial risk of Delta versus that for the five companies..

Q. What other risk analysis did you perform?

A. I compared the capital structure, the cash flows, and published risk measures from Standard and Poor's and Value Line.

Capital Structure

Q. Please discuss the comparison of Delta's capital structure with the capital structure for the five companies.

A. The total capitalization for Delta is shown on Schedule 6 and the capital structure ratios are shown on schedule 7. The 1968 common equity ratios in Schedule 7 are different than the common equity ratios shown on Schedule 3 because the ones in Schedule 7 include current portion of long-term debt and short-term debt as a part of the capitalization. This inclusion implicitly assumes that the debt will be refinanced as it matures.

Total leverage includes short-term debt, long-term debt and preferred stock. All three have fixed capital service payments -- interest for debt and preferred dividends for preferred stock. Also, all three cause the variability in earnings per share to increase relative to the variability in revenues. Delta uses 64.4% fixed capital service payment financing (long-term debt, short-term debt, and preferred stock) as compared to 58.2% for the five companies. Delta has less short-term debt and no preferred stock but a greater amount of long-term debt. This causes Delta to be more risky.

Cash Flow Analysis

Q. Dr. Weaver, would you explain your cash flow analysis?

A. I evaluated cash flow ratios for the years 1997 and 1998. These ratios dealt with the cash flow coverage of interest, total dividends, investing activities, and net income. The data for constructing the ratios were obtained from Delta's financial statements in the Annual Report. The data for the five companies was taken from Compact Disclosure.

Q. Did you use the same cash flow ratios that are used by Standard & Poor's?

A. No. Standard and Poor's excludes changes in working capital accounts in its calculation of the amount of cash available for covering interest, debt, or new plant. The coverage ratios that I use are calculated from "cash flow from operating activities" that is defined by FASB 95.

The exclusion of working capital may be inconsequential when only minor changes occur in the current asset or liability accounts. When large changes occur, however, the amount of cash available for coverage would be either over- or under-stated unless accounted for in the cash flow statement. For this reason, the coverages calculated according to FASB 95 provide better information for the analysis.

Q. Where do you show the cash flow coverages for Delta and for the five gas distribution companies?

A. Data for the individual companies is shown on Schedules 8 through 13. A summary of the cash flow coverages for Delta and the five gas companies is shown on Schedule 14.

Q. What does the cash flow coverage of interest indicate?

A. The cash flow coverage of interest expense indicates how many times cash flow from operating activities covers interest. A low ratio would indicate a greater risk that the firm would have difficulty making its contractual interest payments. A higher ratio would indicate less risk. The stability of the cash flow is also important. A company with a very stable cash flow could have a smaller coverage and still be less risky than a company with a larger coverage but a cash flow that is volatile.

Q. How does Delta's cash flow coverage of interest compare to the five companies' coverage?

A. The cash flow coverage of interest expense was determined by adding interest expense back to cash flow from operating activities and this amount was then divided by total interest expense. The average company in the five company group had a 3.18 times coverage and Delta's cash flow coverage of interest was 3.07 times.

Delta's and the five companies are nearly the same. Delta's cash flow from operating activities would have to fall by more than 207% before there would be insufficient cash flow to make all of its interest payments. For the nine companies as an average, the cash flow from operating activities would have to fall by 218%. In either case, cash flow would have to decrease substantially before there would be any risk of having insufficient cash flow to make interest payments.

Q. Please proceed to discuss the cash flow coverage of total dividends.

A. The cash flow coverage of dividends shows the number of times that internally generated cash flow covers the amount of total dividend payments. A company with a low coverage might be in danger of having to reduce or even eliminate a dividend payment.

Q. What is the cash flow coverage of the common dividends?

A. Delta's cash flow of dividend coverage averaged 2.83 times and the five company group averaged 2.70 times. Once again, these coverages are nearly the same.

Q. What does the cash flow coverage of investing activities represent?

A. The cash flow coverage of investing activities indicates how many times cash flow from operating activities cover long-term investments in plant and other assets. A ratio greater than 1.0 indicates that internally generated funds are sufficient to cover investments if there were no dividend payments or payments to cover maturing financial assets. When the coverage after dividends and maturities exceed the proportion of equity in the capital structure, the company can perform external financing with debt and not have its capital structure equity ratio decline.

The higher the coverage, the less likely the company will be forced to seek substantial external financing to acquire assets. Therefore, a high ratio indicates greater protection from the vagaries of the capital market.

Q. What were the cash flow coverages of investing activities?

A. Delta's cash flow coverage of investing activities averaged .58 times as compared to .72 times for the five gas distribution companies.

Q. What does this indicate?

A. This shows that, since this measure exceed the equity ratios, both Delta and the nine companies would be able to maintain the current debt ratios without external equity financing if there were no dividend payments or debt maturities. For the five companies, there is little risk associated with having to acquire external equity capital for financing fixed assets acquisitions. Internally generated cash flow is sufficient to provide the equity component of the investments in fixed assets. However, Delta, with a lower coverage, has a greater likelihood of having to perform external equity financing than the nine companies.

Q. What does the cash flow coverage of net income indicate?

A. The cash flow coverage of net income is a measure of the quality of earnings. It represents the number of dollars of cash flow from operating activities per dollar of net income reported on the income statement.

Q. What did you find about this coverage measure?

A. Delta's coverage measure averaged 3.62 times while the coverage measure for the nine companies averaged 1.96 times.

Q. What does this indicate?

A. This indicates that both Delta's and the nine companies' reported net income are of high quality. Delta, with $3.62 in cash flow for each $1.00 of reported Net Income has a very high quality of reported net income.

Q. What do you conclude about the cash flow coverage measures?

A. The cash flow measures indicate that, from a cash flow perspective, Delta has nearly the same risk as the five company group. Any risk difference is caused by Delta's potential need for external equity financing for investing activities. However, the Canada Mountain storage field is nearly complete and there will be less construction financing required in 1999. The quality of earnings tends to make Delta less risky than the other companies.

<u>Published Risk Measures</u>

Q. What published risk measures did you examine?

A. The published risk measures are shown in Schedule 15 and 16 of my Exhibit. The comparative measures that I examined were the Standard & Poor's risk evaluation, beta, and Relative Strength and the Value Line Safety Rating and beta.

Q. Why did you examine published risk measures?

A. Many investors rely on published risk measures to make their stock purchase and sell decisions. These measures provide additional information for comparing the risks of the nine companies to the risk of Delta.

Q. You show both Standard and Poor's and Value Line betas. What is Beta?

A. Beta is a measure of systematic risk; that is, risk that is common to all companies in general. Systematic risk could be caused by something like a change in the rate of inflation, or a political event, a war, or a change social-economic conditions. Obviously, some companies have greater exposure to the occurrence of any single event than other companies and they have more systematic risk.

Beta is measured from the company's stock sensitivity to general changes in stock market prices. A beta that equals 1 would represent an average company whose stock price changes are nearly identical to the market. These companies are said to have average systematic risk. Companies that are less risky have Betas less than one and companies that are more risky have Betas greater than one.

Q. What are the Betas for the five gas distribution companies?

A. The Betas for the five companies are shown in the center column on Schedules 15 and 16. The S&P Betas for the five companies average .31 versus an S&P beta for Delta is .02. The Value Line Betas, on Schedule 16, average .60 for the five companies. Delta is not covered by Value Line.

Q. In general, what do these Betas for the gas distribution companies indicate?

A. The five gas distribution companies have about half as much systematic risk as an average company. Delta's beta is lower than the average indicating that it has even less systematic risk than the average company.

Q. Would you continue by describing the Standard and Poor's risk evaluation?

A. The S&P risk rating reports the volatility of the stock's price over the past year. Companies whose stock prices are more volatile are perceived to be more risky.

All of the five gas distribution companies's stocks have low volatility. This indicates that these companies are perceived to be less risky than an average company.

Q. What is the S&P relative strength rank and what does it show?

A. The S&P relative strength rank reports, on a scale of 1 to 99, how the stock has performed relative to the other companies that S&P follows. The stocks of the five companies are ranked between 43 and 91. The average ranking for the five companies is 68. This indicates that the nine are, as a composite, have performed better than an average company. Delta is ranked as having less financial strength. Its ranking is 32.

Q. Dr. Weaver, Schedule 16 shows Value Line measures for safety and beta. Why didn't you include Delta on this page?

A. Value Line does not include Delta in the companies that it follows.

Q. You show a Value Line safety rank. What is this measure?

A. The Value Line Safety Rank is a combination of the Value Line's Financial Strength rating and the Value Line's Stock Price Stability Rating.

Q. What do the Financial Strength and Stock Price Stability ratings indicate?

A. Value Line analysts assess the financial leverage, business risk, company size, and other factors for each of the approximately 1,700 companies that they follow. The result of this assessment is the Financial Strength rating.

The Stock Price Stability Index is based upon a ranking of the standard deviation of weekly percent changes in the price of a stock over the last five years. The top 5% are assigned an index value of 100, the next 5% an index value of 95, and so forth.

Q. How are these combined into a Safety Rating?

A. The approximately 1,700 companies are classified into five groups. Group 1 contains companies that are the safest. The companies in group 5 are the least safe.

Q. What is the Safety Rating for the five gas distribution companies?

A. Four of the five companies have a rating of "2" and one has a rating of "3". The rating "2" represents a safer than average or a below average risk rating. Cascade has a "3" which represents average safety rank.

Q. What do you conclude from your analysis of the published risk indicators for the five companies?

A. The published market measures indicate that the five companies are less risky than an average company. This indicates that the cost of equity for these companies should be lower than the cost rate for an average company. Since Delta is similar to these five companies, it also is less risky than an average company. Its cost of equity will also be lower than the cost for an average company but, if its risk is not reduced by the adoption of the ARP, its cost of equity will be higher than the cost rate for the five companies..

Risk Analysis Summary

Q. Dr. Weaver, please summarize your risk analysis.

A. The five companies in the gas distribution industry that were selected for this analysis have about half as much risk as an average publicly held company. This is indicated by published risk measures, Betas, and cash flows.

Delta is similar to these companies. Its published risk analysis was similar to the five companies in all but its relative strength rank. It is a little more risky from its greater use of financial leverage, its greater operating leverage, and a greater need for external financing. However, its Beta is lower than the Beta of the nine companies, it has strong cash flow interest coverage, strong cash flow dividend coverage, and an excellent quality of earnings.

The Economic Environment

Q. Dr. Weaver, what economic measures did you consider in your review of present and perspective economic conditions?

A. I considered the business cycle as measured by Gross Domestic Product (GDP), the inflation rate as measured by the Consumer Price Index (CPI), interest rates, and forecasts of economic measures.

Q. What measure of the business cycle did you examine?

A. I examined the percentage real rate of change in GDP. This measure provides the rate, in inflation adjusted values, at which the final output of goods and services are consumed in our domestic economy. Positive values indicate a growing economy and negative values indicate a declining economy.

The rate of economic growth provides a mixed message for investors. Too high a growth rate could be inflationary. The inflation would be caused by the demand for goods and services outstripping the supply. A negative growth indicates recession. An ideal growth rate is in a range from 2% to 4%. The real change in GDP has been in this range since 1992.

Q. What did you find?

A. The data is provided in Schedule 17. This Schedule shows the real rate of change in GDP since 1976. During this period, there have been three downturns in economic activity during this period; in 1980, in 1982, and in 1991. Since 1992, our economy has been growing at a rate between 2.3% and 3.9%. Schedule 18 provides the Value Line forecast for the expected change in GDP through 2003. This forecast indicates that the growth in the economy over the next five years is expected to be similar to the growth of the previous five years.

Q. What do the measures show about inflation?

A. Schedule 17 also shows the percentage change in the CPI for the period 1976 through 1998. Since 1992, the rate of change in the CPI has been below 3%. Schedule 18 shows that the rate of inflation is expected to be below 2.8% for the next five years.

Q. Please discuss the interest rate data that you examined.

A. Schedule 19 shows Moody's Public Utility Bond Yields since 1980. This schedule provides the annual average rates from 1980 through 1998 and monthly average rates for January through May, 1999. During 1999, the rates for A rated utility bonds have ranged from a low of 6.97% in January to a high of 7.47% in May. The interest rates have risen from January to May, 1999 but the yield spread has narrowed. Investors are not demanding and receiving a consistently larger risk premium for riskier-lower rated bonds. This indicates that the rise in interest is a result of monetary policy rather than a change in investor confidence.

In contrast, consider 1984, when the growth rate of the economy was 6.2%, a rate at which some analyst thought could kindle inflation, the spread was larger in this year. It ranged from 12.72% to 14.53%, a spread of 181 basis points. A low yield spread generally indicates a high level of investor optimism and a high yield spread indicates pessimism..

Q. What does the forecast for interest rates indicate?

A. Schedule 20 shows the forecast for 3-month Treasury Bills and 10-year Treasury Bonds through the year 2003. The forecast for the Bills indicates that short-term rates are expected to be near the same rate as they have been in the previous five years. Longer-termed rates, as indicated by the Bonds, are expected to be 114 basis points lower over the five year forecast period. The average rate for 1994 through 1998 was 6.70% and the average for the five year forecast is 5.56%. This forecast indicates that investors are optimistic.

Q. What do you conclude from this analysis?

A. The expected economic growth, inflation, and level of interest rates should permit capital costs rates to remain at or near the existing low levels.

Cost of Equity

Q. Dr. Weaver, you stated earlier that you used the DCF, the CAPM, and Bond-Yield-Risk-Premium methods in your analysis. Which method for obtaining information to estimate the cost of equity will you use first?

A. I will implement the DCF results first. This will be followed by the CAPM results. The Bond-Yield-Risk-Premium will be last.

<u>DCF Method - Historical Growth Rates</u>

Q. What is required to implement the DCF method?

A. The DCF method requires an estimate for the growth of dividends and market prices, and a dividend yield.

Q. How did you determine the growth estimate for use in the DCF model?

A. There are a variety of ways to estimate the rate of growth for dividend and market prices. These include using historical data to extrapolate growth based what happened in the past. Another is using analysts' forecast of earnings growth. The use of a variety of measures for estimating growth are discussed in Appendix II.

Q. What measures of historical growth did you use in the DCF model?

A. I used three measures of historical growth. These were the compound growth rate in: (1) DPS, (2) EPS, and (3) BVS.

Q. Why did you use the historical EPS, DPS, and BVS for providing growth estimates?

A. I use the EPS, DPS, and BVS because these measures are generally considered to be better proxies for growth when using historical data to estimate growth. Dividends and book value are directly related to each other and EPS contribute to each measure -- the amount of EPS not paid as dividends increases the book value of equity.

Q. What years did you use to obtain data for the historical growth estimates?

A. The rates were compiled by Value Line for the period 1989-1998 from the annual rates for the past ten years.

Q. What were the historical growth rates?

A. The historical growth rates are shown on Schedule 21. The growth rates are 3.4% for EPS, 1.7% for DPS, and 3.8% for BVS for the five companies. Delta's growth rates for the period 1989-98 were (0.3%) for EPS, 0.7% for DPS, and 0.5% for BVS.

Q. Are these growth rates fairly stable over ten years you examined?

A. No. There has been a large amount of variability in the EPS over this period. EPS was \$1.07, \$0.76, \$0.73, \$1.52, \$1.60, \$1.50, \$1.04, \$1.41, \$0.75, and \$1.04 for the years 1989 through 1998. In spite of the EPS variability, Delta was able to maintain a relatively constant and slowly growing dividend. During the same period, dividends increased from \$1.12 to \$1.14 per share.

Q. Dr. Weaver, what appear to be the greatest cause of the fluctuations in EPS?

A. The majority of the fluctuations in EPS are weather related. For example, from 1994 to 1995, retail sales volume fell from 4.3 billion cubic feet to 3.7 billion cubic feet and EPS fell from \$1.50 to \$1.04. In the same two year period, heating degree days had fallen from 106.1% to 89.5% of the 30 year average. From 1996 to 1997, when EPS fell from \$1.41 to \$0.75, degree days went from 112% to 103% of the 30 year average.

Q. Would weather also cause fluctuations in the sample companies you selected.

A. Yes. Delta has a larger residential and commercial load than the five companies so it would be somewhat more adversely affected by weather. A sampling of the Value Line and S&P Stock Reports text indicates that in 1998, all of the companies were hurt by a warmer than usual heating season.

DCF Method - Forecasted Growth Rates

Q. What were the sources you used to obtain the analysts' forecast?

A. I used data published by I/B/E/S and Value Line. I obtained the I/B/E/S estimates from Compact Disclosure and the Value Line from their published company reports.

Q. How are the I/B/E/S and Value Line forecasts compiled?

A. I/B/E/S does monthly surveys of analysts' earnings forecasts. The ones I used were taken from the May 1999 Compact Disclosure CD. Most forecasts would have been made in early 1999. Value Line in-house analysts make the three to five year forecasts for revenues, cash flow, EPS, DPS, and BVS that appear in that publication.

Q. What were the projected growth rates?

A. The growth forecasts for the individual companies are shown on Schedule 22.

Q. Would please provide a summary of these rates.

A. A summary of the growth rates are:

Historical Data:

	5 Companies	Delta
EPS	3.4%	(0.3%)
DPS	1.7	0.4
BVS	3.8	0.5

Analysts' Forecasts:

I/B/E/S-EPS	5.5	3.5
Value Line:		
EPS	6.8	
DPS	1.4	
BVS	5.3	

Q. How do you use these data to determine the cost of equity in the DCF model?

A. The growth estimates are combined with an expected divided yield to provide a range of values for the cost of equity. The actual cost of equity is determined in the capital market by investors who are buying and selling shares of stock. This range of values provides insight into likely investor thinking about these companies.

Q. How would an investor use a low growth rate such as the 1.7% historical growth rate in DPS or the 1.4% forecast DPS growth rate in their decision making?

A. The low growth performance relative to the growth of other opportunities with similar risk would cause an increase in sell decisions unless it is offset by a high dividend yield. Without a dividend yield offset, the low growth rates would have an opposite effect on the cost of equity. A large number of sell decisions would drive the stock price down and cause the cost of equity to be higher. This doesn't happen because where low growth expectations occur, the stocks have higher dividend yields.

Q. Dr. Weaver, how do the low growth rates effect your analysis of the cost of equity?

A. I do not depend on the DCF model as a sole source of information for augmenting my judgement.. I also use information obtained from the CAPM and from the bond-yield-risk-premium method.

Q. What data did you use to calculate the dividend yield?

A. The dividend yield was calculated by dividing the current annual dividend rate by the average stock price for June 24 through July 8, 1999. The annual dividend rate was determined by multiplying the most recent quarterly dividend amount by four. Schedule 23 shows the dividend calculation. The average dividend yield for the five companies was 4.03% and for Delta, it was 6.66%.

Q. Why is Delta's dividend yield so much higher than the five company average?

A. Investors have lower growth expectations for Delta than for the five companies.

Q. Why did you use the dividend rate rather than the actual amount of dividends paid the previous year to calculate the dividend yield?

A. Dividends are paid quarterly. The rate, based on the latest quarterly amount multiplied by four, is higher and compensates for not compounding the dividends on a quarterly basis.

Q. How did you apply the dividend yield to the DCF model?

A. The DCF model requires an expected divided yield rather than a historical dividend yield. The expected yield is determined by multiplying the current yield times one plus the growth rate. The growth rate estimate is then added to the expected dividend yield to obtain an estimate of the cost of equity.

Q. What were your results?

A. The DCF results are summarized below:

Five Companies: Forecasts:	Growth Rates	Dividend Yield	Adjusted Dividend Yield	Estimate for the Cost Of Equity
I/B/E/S	5.5%	4.03	4.25	9.75%
VL - EPS	6.8	4.03	4.30	11.10
VL - DPS	1.4	4.03	4.08	6.02
VL - BVS	5.3	4.03	4.24	9.54
		Average I/B/E/S & VL EPS----------		10.43
		Average Excluding VL-DPS----------		10.13
Historical:				
EPS	3.4	4.03	4.17	7.57
DPS	1.7	4.03	4.10	5.80
BVS	3.8	4.03	4.18	7.98
		Average Excluding DPS ---------------		7.78
Delta EPS Forecast:				
I/B/E/S	3.5	6.66	6.89	10.39

Q. Dr. Weaver, did you make a flotation cost adjustment?

A. No, I did not. A flotation cost adjustment should not be used for this cost of equity determination. According to the 1998 Stockholders Annual Report, capital expenditures will be $6.8 million in 1999, down from the $11.2 million that occurred in 1998. The Employee Stock Purchase Plan provided for $101 thousand in new equity in 1998. In response to the PSC question 6 in the June 4 data request, Witness John Hall indicated that Delta does not have any financing plans through fiscal year 2001.

Q. What do the DCF results indicate?

A. The DCF results indicate that the cost of equity is in the 7.8% to 10.5% range. When the analysts forecasts of EPS is used, the equity cost rate was 10.39%. The average I/B/E/S and Value Line EPS for the five companies indicate a rate of 10.43% while the average that includes EPS and BVS indicate that the cost of equity is close to 10.13%. When the historical growth rates and the forecasted DPS growth rate are used, the DCF results indicate that the cost of equity is closer to 8%.

This information will be used with the information that was obtained from the CAPM and bond-yield-risk-premium methods.

CAPM Results

Q. What do the CAPM results show?

A. The CAPM results are shown in Schedule 25. The average of the results for the five companies was 9.24%. This average was calculated using different proxy data for the risk free rate, the market return, and beta. There were 24 different combinations of data examined. The standard deviation of the 24 outcomes was 1.53. This indicates that 68% of the time, the actual results would be in a range that is from 7.71% to 10.77% (the average +/- one standard deviation). This is very close to the same range found using the DCF model.

Q. You used both long-term and short-term rates in your analysis. Which is better?

A. A government bond rate is normally used for the risk-free rate. Some analyst argue that since common stock tends to be a long-term investment, long-term government bond rates should be used for the risk-free rate. Others argue that a short-term rate should be used because it is more nearly risk free because it doesn't have as large of an inflation or marketability premium embedded in it. Due to this uncertainty about the use of a long- or short-term rate, I used both. I do this because some investors may use either rate to form their expectations. The purpose of the models is to provide insight about investor thinking.

Bond Yield-Risk Premium

Q. Dr. Weaver, how did you implement the bond-yield-equity-risk-premium method?

A. An equity risk premium is required for this approach. I performed a study of the equity risk premium for the five companies that were selected as being comparable to Delta. The risk premium study is provided in Schedules 26 through 31.

The risk premiums represent the difference between the total return on the common stock and the total return on 10-year government bonds for the period 1989 through 1998. To make this determination, I constructed a matrix of total returns on all possible annual holding periods on the five company portfolios of the common stock. Each company is equally weighted in the portfolio. I constructed a similar matrix of total annual returns on a portfolio over ten year government bonds. For each year, I subtracted the bond returns from the stock returns to obtain the premiums. The average for those premiums was 4.52%

Q. How did you use the risk premiums?

A. I added this premium to the current and forecasted 10-year government bond rates to obtain an estimate for the cost of equity.

Q. What current and forecasted rates did you use?

A. I used three rates: a current 10-year government bond rate @ 6.3%; a 2-year forecast of the 10-year rate @ 5.75%; and a long-term projected 10-year bond rate @5.40%.

Q. Where did you obtain these rates?

A. The current rate was obtained from the Federal Reserve Statistical Release on July 2, 1999. The forecasted rates are from the Congressional Budget Office "Update" published on July 1, 1999.

Q. What results did you obtain using these rates?

A. When the current bond rate of 6.30% is added to the 4.52% risk premium, the result was 10.82%. The 1999-2000 forecasted rate in the Congressional Budget Office Economic and Budget Outlook published July 1, 1999 was 5.75% and this results in a cost of equity of 10.27%. The longer-term projection in the CBO Outlook was 5.40% and this results in a cost of equity of 9.92%.

A range from 9.92% to 10.82% encompasses the results using the different interest rates. These results near the upper-end but overlap the ranges found using the DCF and CAPM models.

Q. Please provide a summary of the results of the three methods.

A. The results of the three methods are:

DCF	7.8%-10.4%
CAPM	7.7%-10.8%
Bond-Yield-Risk-Premium	9.9%-10.8%

Q. Dr. Weaver, what is the cost of equity for Delta?

A. The cost of equity for Delta, only if the ARP is not accepted, is in a range from 10.25% to 11.25%.

Q. How did you reach this conclusion?

A. First, I found that the five gas distribution companies are less risky than Delta. However, the difference in risk is small. Delta's cash flow ratios are as strong and in some cases stronger than the five companies. Delta has more long-term debt in its capital structure but the five companies have more short-term debt and current liabilities than Delta. Short-term debt is riskier than long-term debt because it must be paid or refinanced at the rates in existence at the time of refinancing so there is less certainty about locked-in rates. However, even when long-term and current liabilities are combined, Delta has more leverage and is more risky. Also, Delta is smaller, has a larger space heating load, and its service territory is such that more asset investment is required to service its customers.

The cost of equity for the five companies would average 9.75% to 10.75%. I increased this range by 50 basis points to account for the greater risk of Delta. This results in the 10.25% to 11.25% range.

Q. Dr. Weaver, how would the adoption of the ARP effect your recommendation?

A. The adoption of the ARP will lower Delta's cost of equity.

Q. Why do you think the adoption of the ARP will lower its cost of equity?

A. The adoption of the ARP, even on a three-year experimental basis, will considerably lower investor's risk expectations regarding Delta. The fact that the PSC is willing to consider the ARP to the extent that it would be willing to try it for a three-year period will send a signal to the investment community that the Commission is open to some form of an alternative regulatory plan. Rational investors will realize that any alternative regulatory plan that Delta would propose would contribute toward greater earnings stability. Consequently, a definite signal will be sent and the only way that signal could be interpreted would be -- lower risk.

Q. Dr. Weaver, Delta is proposing that the cost of equity for the ARP remain at the 11.1% to 12.1% range found in the order in Case No. 97-066 dated December 8, 1997. Would you please comment on this?

A. The 11.1% to 12.1% range should <u>not</u> be used to establish rates for the ARP methodology. The Commission established the 11.1% to 12.1% range in a case that used, and assumed Delta would continue to use, a return on rate base methodology.

The ARP rate making methodology is considerably different from the return on rate base method for rate setting, is automatic, has make-whole provisions, and reduces the risk of the regulated company.

Q. What are some of the major differences in the ARP?

A. The ARP method, as proposed by Delta, would cause customer rates and gas revenues to be adjusted automatically on an annual basis so that the return on equity is within 50 basis points of the mid-point of the return authorized by the Commission. In addition, rates each year would be set to cover budgeted expenses rather than historical expenses. Setting rates on a budgeted, or forward-looking, basis would further stabilize the return on equity because, in some instances, the changed revenues will be collected prior to the higher expenses are realized.

The proposed ARP method very nearly guarantees that Delta will earn a return on equity that is close to the return authorized by the Commission. The *Bluefield* and *Hope* Supreme Court mandates provide that the return should be similar to other companies that have comparable risk. The ARP will cause Delta's risk to be lower because the return will be guaranteed within a limited range of fluctuations. A nearly guaranteed return will cause Delta's common stock to be somewhat similar to a bond that participates in the earnings growth through an increasing dividend and increasing market prices..

Q. What risk elements would be reduced by the ARP?

A. The *Prospectus* accompanying the $25,000,000 bond issue that was dated March 23, 1998 provides a listing of 17 specific risk factors on page 5. Twelve and perhaps more of these sources would be eliminated or greatly reduced by the ARP. These include:

Fluctuations in demand attributable to weather.

. New Business and operational requirements for gas supply resulting from changes in federal regulation of interstate pipelines.

Competition with alternative sources of energy.

Uncertainty in achieving an adequate return on invested capital due to inflation.

Difficulty in obtaining rate increases from regulatory authorities in adequate amounts and on a timely bases.

Uncertainty in recovery of gas cost.

Attrition in earnings produced by the combination of increasing expenses and the costs of new capital which may exceed allowed rates of return.

Volatility in the price of natural gas.

Increases in construction and operating costs.

Environmental regulations and costs of environmental remediation.

The possibility of change from cost-based rate regulation.

Uncertainty in the projected rate of growth of customers' energy requirements.

Q. What major equity risk elements would remain if the ARP were to be adopted?

A. The stock owners will remain as a residual claimants with regard to earnings distribution; the return on equity will be subject to be changed from time to time rather than being fixed over some term; and common stock is outstanding in perpetuity rather than being similar to fixed-term bond that matures at a known value. In addition, there is a potential two and one-half year lag in truing-up rates so that the return on equity within the 50 basis point band is realized.

Q. Dr. Weaver, please explain the delay that could occur before the return on equity is fully realized.

A. The Actual Adjustment Factor and the Balancing Adjustment Factor serve as true-up mechanisms to collect any short-falls from the budgeted year. Based on the "Component Timeline" in Table 5.0, there could be a lag of 2.5 years before the company is made whole. Since money has a time value, and the return would be "trued-up" with smaller or discounted dollars and this would represent a source of risk to equity holders. This source of risk is small relative to the current risk where no true-up occurs.

Q. How did you determine the amount of reduction in risk premium from your analysis?

A. I reduced equity risk premium by 25% and added the new, lower risk premium to the risk-free rate that is represented by government bonds.

Q. Dr. Weaver, the ARP would appear to provide much greater stability to the cost of equity. What is your rationale for reducing the risk premiums by only 25%.

A. It not certain at this time what modifications might need to be made to the ARP if it is approved in its present form. There could be changes that need to be made to prevent over- or under-earning. There is a natural scepticism that investors will have until the ARP has been tested by time.

Q. What were the risk premiums that you reduced?

A. In the bond-yield-risk-premium study, the risk premium was 4.52%. Schedule 42 provides the risk premiums according the CAPM. These are 3.98%.

Q. What was the effect of the risk premium reduction?

A. The risk premiums were reduced and rounded to 3.0% to 3.4%.

Q. What risk-free rates did you use?

A. I used the same rates that I used in the CAPM analysis and in the bond-yield-risk-premium study.

Q. What results did you obtain?

A. The results are:

Risk-free Rate	Rate plus Risk Premium @ 3.0%	Rate plus Risk Premium @ 3.4%
6.30%	9.30%	9.70%
5.75%	8.75%	9.15%
5.40%	8.40%	8.80%
4.80%	7.80%	8.20%
4.50%	7.50%	7.90%
Average	8.35%	8.75%
Midpoint	8.55%	

Q. What cost of equity would you recommend if the ARP is approved by the Commission?

A. The cost of equity should be from 8% to 9% if the proposed ARP is adopted. This return is comparable to other investment opportunities that have similar risk.

Weighted Average Cost of Capital

Q. Dr. Weaver, what capital structure did you find for Delta?

A. The capital structure that I used is shown in Schedule 34. This structure is the same as the structure shown in Schedule 7.

Q. What cost rates did you find for this capital?

A. I used 6.742% as the cost of short-term debt. This is the average daily rate on short-term debt in fiscal year 1998. This calculation was provided by Delta in response to the first AG's data request, question 51.

I found the cost of long-term debt to be 7.63%. I used the Yield to Maturity (YTM) for these calculations. Schedule 33 shows the YTM calculation.

Q. What did you find the cost of capital to be?

A. The cost of capital is in a range from 7.74% to 8.08%. This is the rate that I recommend be used for this proceeding if the ARP is adopted.

Q. Dr. Weaver, does this conclude your testimony?

A. Yes.

Statement of Qualifications

for
Carl G. K. Weaver

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I was with the Virginia State Corporation Commission from June, 1976, to August, 1979. This Commission has regulatory authority over public utilities, banks, insurance companies, railroads, and motor carrier transportation companies operating in Virginia. In July, 1977, I founded the Economic Research and Development Division at the Virginia SCC and became its first Director.

The Economic Research and Development Division was established to provide financial and economic support for other divisions of the Commission. Prior to founding it and becoming its first Director, I served the Commission as a public utility financial and economic analyst in the Public Utility Accounting Division.

During this time, I also was a lecturer in the Graduate School of Business Administration of the College of William and Mary. I taught a course in portfolio theory in the fall semester of 1977 and 1978, and in the spring semester of 1979.

I left the State Corporation Commission and joined the faculty of James Madison University in August, 1979. While at JMU, I worked with M.S. Gerber and Associates, Inc., a utility consulting firm. I participated in the development of the Financial Information Model and the Midas Model which is marketed by EPRI. I also served as

Director of JMU's M.B.A. program for the years 1993-1995. I retired at the end of June, 1998 and am an Emeritus Professor of Finance at JMU. I am also serving as an adjunct professor of finance at Eastern Mennonite University.,

Prior to joining the State Corporation Commission, I was an assistant professor of Finance at Virginia Commonwealth University from 1967 through 1976. I taught courses in financial management, investments, and decision mathematics. I received a leave of absence from V.C.U. from September, 1971, to June, 1973, to pursue and complete the course work for a doctoral degree at Florida State University. I was awarded the Doctor of Business Administration degree in June, 1975. I majored in finance and minored in statistics.

I was a field manager with Ford Motor Company prior to joining Virginia Commonwealth University. A large portion of the job activities consisted of performing financial analysis of dealers in an assigned zone and advising them in financial management so that they would be in a better position to represent Ford Motor Company and sell its products. Other duties included assisting dealers in negotiating financing arrangements. I was employed by Ford in 1964. My military service also provided me with financial experience. I was in the Finance Corps and spent the majority of my active duty at the Finance and Accounting Office at Fort Dix, New Jersey.

Q. DR. WEAVER, PLEASE SUMMARIZE YOUR EXPERIENCE AS AN EXPERT WITNESS.

A. The duties of the Economic Research and Development Division included providing financial and economic expert testimony before the Commission regarding fair rate of return and other matters. As director of the Economic Research and Development Division, I provided financial and economic expert testimony before the Virginia Commission. The topics of testimony included the cost of capital, capital structure, cash flow analysis, attrition, and sale and lease-back financing arrangements. I have also provided testimony before the Kentucky Public Service Commission and in other jurisdictions.

Q. PLEASE IDENTIFY THE CASES FOR WHICH YOU PROVIDED TESTIMONY.

A. I testified in twenty-two cases concerning utility matters before the Virginia State Corporation Commission. These cases and their topical areas are as follows: Virginia Electric and Power Company's application for approval for the financial arrangement for an office building in Case No. 19734; ex parte in regard to investigation of the fuel adjustment clauses of Appalachian Power Company, et al. in Case No. 19526; on attrition on Potomac Electric Power Company's application for an increase in rates in Case No. 19686; on rate of return in Appalachian Power Company's application for an increase in rates in Case No. 19723; on merger and rate of return in Norfolk and Carolina Telephone Company of Virginia's application for an increase in rates in Case No. 19727; on rate of return in General Telephone Company of Southeast's application for an increase in rates in Case No. 19778; on rate of return in Potomac Edison Company's application for an increase in rates in Case No. 19810; on cash flow analysis in Virginia Electric and Power Company's application for an increase in rates in Case No. 19730; on fuel adjustment clause in the investigation of Virginia Electric and Power Company's clause in Case No.

19818; on rate of return in Amelia Telephone Corporation's application for an increase in rates in Case No. 19891; on rate of return in Virginia American Water Company's application for an increase in rates in Case No. 19903; on rate of return in Clifton Forge - Waynesboro Telephone Company's application for an increase in rates in Case No. 19910; on rate of return in Virginia Pipe Line Company and Lynchburg Gas Company's application for an increase in rates in Case No. 19919; on rate of return in Shenandoah Telephone Company's application for an increase in rates in Case No. 19920; on rate of return in Roanoke Gas Company's application for an increase in rates in Case No. 19985; on rate of return in Columbia Gas of Virginia, Inc.'s application for an increase in rates in Case No. 19988; on rate of return in Washington Gas Light Company's application for an increase in rates in Case No. 19992; on rate of return in General Telephone Company of the Southeast's application for an increase in rates in Case No. 20003; on rate of return in Virginia American Water Company's application for an increase in rates in Case No. 20039; on rate of return in Old Dominion Power Company's application for an increase in rates in Case No. 20106; on rate of return in Virginia American Water Company's application for an increase in rates in Case No. 20177; and on rate to return in Virginia American Water Company's application for an increase in rates in Case No. PUE790021.

I presented testimony before the Commonwealth of Kentucky's Public Service Commission on CWIP in Louisville Gas & Electric Company's application for an increase in rates in Case No. 7799; on CWIP in Kentucky Utility Company's application for an increase in rates in Case No. 7804; on Union Light, Heat and Power Company's application for rate increase Case No. 8046 and Case No. 9029; on rate of return in

Louisville Gas & Electric Company's applications for an increase in rates in Case No. 8284, in Case No. 8616, in Case No. 8924; and in Case No. 10064; on rate of return in Kentucky Utility Company's application for an increase in rates in Case No. 8624; on Louisville Gas & Electric Company's continuance of construction on Trimble County Unit Number 1 in Case No. 9243, and on rate of return in General Telephone Company of the South's application for an increase in rates in Case No. 9678, on rate of return in Kentucky-American Water Company's application for an increase in rates in Case No. 89-348, on rate of return in Western Kentucky Gas Company's application for an increase in rates in Case No. 90-013, on rate of return in Union Light, Heat and Power Company's application for an increase in rates in Case No. 90-041, on rate of return in Louisville Gas and Electric Company's application for an increase in rates in Case No. 90-158, on rate of return in Union Light, Heat and Power Company's application for an increase in rates in Case No. 91-370, on rate of return in Union Light, Heat and Power Company's application for an increase in rates in Case No. 92-346, on rate of return in Kentucky-American Water Company's application for an increase in rates in Case No. 95-554, on rate of return in Delta Natural Gas Co., Inc.'s Case No. 97-066, and on cost of equity in Louisville Gas and Electric Company's and Kentucky Utilities Company's application for approval of an alternative method of regulation of its rates and services.

Also, I presented testimony in five cases before the Interstate Commerce Commission regarding cash flow analysis and rate of return. These cases were heard on ICC Docket Numbers 37339F, 37354, 37322, 37507, I&S Docket Number 9242F, Case No. 37516, and Ex Parte hearing numbers 415 and 436.

In addition, I presented testimony in four cases before the Ontario Energy Board. These involved an accounting policy for Union Gas Limited's gas take-or-pay contract in E.B.R.O. 418, and rate design issues involving ICG Utilities, Ltd., Consumers Gas Company, Ltd., and Union Gas Limited in E.B.R.O. 410-2, 411-2, 412-2, 414-2, 429, and 430-1.

I testified in three cases before the Washington, D.C. Public Service Commission and one before the New Hampshire Public Service Commission involving the use of the Regulatory Analysis model (RAm) for analyzing regulatory policies and evaluating the economic feasibility of converting an oil-generating plant to coal. This testimony was presented in Case Numbers 715, 737, and 759 in Washington, D.C. and in Case No. DE80-175 in New Hampshire. I also testified in one case before the Oklahoma Corporation Commission on rate of return for Arkansas-Oklahoma Gas Company in Cause PUD No. 000079.

Q. WHAT OTHER WORK HAVE YOU DONE IN REGARD TO PUBLIC UTILITY REGULATION?

A. I served as a faculty member for the NARUC Annual Regulatory Studies Program held at Michigan State University in the summers of 1982, 1983, 1984, and 1985. I taught the sessions in public utility accounting and financial analysis at this institute.

I have also authored or co-authored the following articles which have appeared in the Public Utilities Fortnightly: "Cash Flow Statement and Risk Evaluation", published February 15, 1990; "The Future of Competition in the Telecommunications Industry", published March 5, 1987; "Capital Structure Maintenance: A Challenge for Public

Utilities", published September 4, 1986; "The Accelerated Cost Recovery System - A Catch 22?", published May 13, 1982; "A Resolution of the Rate Base Construction Work in Progress Controversy", published April 15, 1982.

In addition, I have presented papers to professional associations and have served on several panels in regard to regulatory matters.

VITA

NAME: Carl G. K. Weaver

ADDRESS: 4713 Wengers Mill Road
Linville, VA 22834

TELEPHONE: (540) 833-1461

EDUCATION:

1975, D.B.A., Florida State University, Tallahassee, FL

1969, M.S., Virginia Commonwealth University, Richmond, VA

1964, B.S., Virginia Commonwealth University, Richmond, VA

EXPERIENCE:

July 1998 - Present	Professor Emeritus James Madison University
August 1979 - June 1998	Professor of Finance James Madison University
January 1993- December 1995	Director of the MBA Program James Madison University
January 1981 - March 1989	Principal, M. S. Gerber & Associates, Inc., Columbus, OH; a utility company consulting firm.
May 1976 - August 1979	Director, Division of Economic Research and Development, Virginia State Corporation Commission, Richmond, VA
August 1977 - May 1979	Lecturer in Finance, College of William and Mary, Williamsburg, VA
August 1968 - March 1976	Assistant Professor of Finance, Virginia Commonwealth University, Richmond, VA

February 1964 - August 1968	Field Manager, Ford Marketing Division, Ford Motor Company.

MILITARY:

October 1959 - February 1962	Finance Corps., U.S. Army

PUBLICATIONS:

Articles (Refereed)

"Bond Ratings: A Poor Predictor of Equity Risk," Public Utilities Fortnightly, October, 1994.

"Risk Evaluation Using the FASB Cash Flow Statement," Public Utilities Fortnightly, February, 1990.

"The Future of Competition in the Telecommunications Industry," Public Utilities Fortnightly, March 1987, Co-author.

"Capital Structure Maintenance: A Challenge for Public Utilities," Public Utilities Fortnightly, September 1986, Co-author.

"The Accelerated Cost Recovery System - A Catch 22?," Public Utilities Fortnightly, May 1982, Co-author.

"A Resolution of the Rate Base Construction Work in Progress Controversy," Public Utilities Fortnightly, April 1982, Co-author.

"Systematic Risk Reduction through International Diversification," Review of Business and Economic Research, XV Fall 1979, Co-author.

"The Organized Options Market," Virginia Social Science Journal, 11, April 1976.

"Evaluation of Portfolio Performance Using a Paired Difference T-Test," Atlantic Economic Journal, IV April 1976, Co-author.

OTHER PUBLICATIONS

"Stable Utility Rates to Benefit Consumers," Lawyers Title News: Economic Forecast Issue, January-February 1984.

Feasibility of the Conversion of Shiller Units 4, 5 and 6 and Newington Station from Oil to Coal Generation, Report to the New Hampshire Public Utilities Commission, May 1981, Co-author.

A Study of the Feasibility of Energy Distributing Companies to Finance Home and Business Insulation, Report to the Governor and General Assembly of Virginia, Richmond: Department of Purchases and Supply, November 1978, Co-author.

"Tax Planning in Real Estate Investments: A Case Study," presented at and published in Proceedings of International Association for Financial Planning, 1986 Academic Symposium, Chicago, Illinois, October 1986.

"Public Utility Diversification and the Cost of Capital," presented and published in Proceedings of NARUC Biennial Regulatory Information Conference, Columbus, Ohio, September 1986.

"The Electric Utility Industry's Financial Challenges for the Ninety's," presented at annual conference, National Association of Regulatory Commissioner's Sub-Committee on Computers, Salt Lake City, Utah, February 1986, Co-author.

"An Evaluation System for Utility Financing Authority Applications," presented and published in Proceedings of NARUC Biennial Regulatory Information Conference, Columbus, Ohio, September 1984, Co-author.

"Micro-Computer Applications for Regulation," presented and published in Proceedings of NARUC Biennial Regulatory Information Conference, Columbus, Ohio, September 1984, Co-author.

Other Publications:
(continued)

"Use of Computer Models in Regulatory Analysis," presented at annual conference, National Association of Regulatory Commissioner's Sub-Committee on Computers, Indianapolis, Indiana, May 1983, Co-author.

"Budgeting and Control in a Not-for-Profit Environment," presented at annual conference, Virginia Association of Children's Homes, Roanoke, Virginia, November 1982.

"Regulatory Considerations for Removal of AFUDC," presented and published in Proceedings of NARUC Biennial Regulatory Information Conference, Columbus, Ohio, September 1978, Co-author.

"A Temporal Evaluation of Risk for Regulated Firms," presented and published in Proceedings of Southwestern Finance Association, New Orleans, Louisiana, March 1977, Co-author.

"An investigation of the Impact of International Diversification on Homogeneous Groupings of Financial Markets," presented and published in Proceedings of Southwestern Finance Association, San Antonio, Texas, March 1976, Co-author.

"Characteristics of Option Premiums: Development of a Valuation Model," presented and published in Proceedings of Atlantic Economic Society, Washington, D.C., September 1975.

PROFESSIONAL ACTIVITIES:

Faculty Marshall, James Madison University, 1997-98.

Speaker, Faculty Senate, James Madison University, 1996-97.

Chair, MBA Program Review Committee, James Madison University.

PROFESSIONAL ACTIVITIES
(continued)

Member, Presidential Search Committee, James Madison University

Receipient of Graduate Faculty Teaching Award, College of Business, 1990-91 Academic Year.

Chair, Principal Committee on Administrative Processes, Financial Resources, James Madison University Self-Study for Accredation by the Southern Association of Colleges and Schools, 1990-1991 Academic Year.

Founded and became first Director of the Economic Research and Development Division of the Virginia State Corporation Commission.

Co-developer of FIN, the Financial Information Model. This micro computer based, financial simulation, strategic analytical model has been adapted for use by five state regulatory commissions and by the planning departments of nine electric and gas distribution companies. Its logic has been adapted by EPRI in the MIDAS model and by Decision Focus in the LMSTM model.

Developed and conducted three day seminars on the application of financial analytical techniques in regulation for the Staffs of the Pennsylvania Public Utilities Commission, Maryland Public Service Commission, Maine Public Utilities Commission and the Ohio Public Utilities Commission.

Served as expert cost of capital witness on behalf of regulatory commission staffs, regulated companies, and state attorney generals in over forty-five electric utility company, gas distribution company and telephone rate proceedings.

Served as expert cost of capital witness on behalf of regulated companies or industry trade associations in annual generic proceedings before the Interstate Commerce Commission for determining measures of railroad revenue adequacy in years 1981-1984.

PROFESSIONAL ACTIVITIES
(continued)

Served as a consultant before state regulatory commissions in numerous proceedings for the evaluation of utility accounting procedures, utility company construction programs, and external financing arrangements.

Served as faculty member, NARUC Annual Regulatory Studies Program, Michigan State University for the years 1982-1985.

Served as panelist on:

Competition in the Telecommunications Industry, New England NARUC meeting, Dixville Notch, NH, 1987;

Workshop on Micro-Computers, APPA national meeting, 1983;

Treatment of P & C Insurance Income, Virginia SCC, 1981;

DOE's Workshop on National Energy Act, December, 1978; and

Outlook for Energy Costs, Valley Economic Seminar, 1977.

APPENDIX II

Concepts of Cost of Capital, Risk, Cost of Equity and Cost of Equity Evaluation Methods

Q. Dr. Weaver, would you please briefly discuss the concept of the cost of capital?

A. The cost of capital represents the price paid for acquiring money from the capital market. To obtain capital, a firm issues financial assets such as shares of stock, bonds, or notes to investors. A financial asset represents a claim on the earning power and property of the issuer. The priority and security of the claims depend upon the contractual conditions associated with each type of financial asset. Because of variation in the contracts, risk differs among the shares of stock, bonds, or notes.

The shares of stocks, bonds or notes are generally issued to investors through an investment bank or a commercial bank. An investment bank is the intermediary between the demanders and the suppliers of long term funds. The commercial bank is the intermediary between the demanders of funds and the money market.

In some instances where subsidiary financing is involved, the parent corporation obtains its funds from the capital market. The subsidiary issues financial assets to the parent in exchange for these funds. In other instances, the subsidiary may place bonds and notes directly with an insurance company or other lender. In this direct placement case, the involvement of an investment bank is limited to locating the lender, assisting in the transaction, or may not be used at all.

The capital market differs from the market for real goods because the item traded in exchange for the financial assets, money, is homogeneous. Investors are the suppliers of money to this market. At any moment in time, the financial assets, shares of stock, bonds or notes issued by different firms are competing with one another for investors' funds. Investors are offered a broad range of choices with respect to the selection of the firms in which they invest and with respect to the form of the instruments which describe the rights and obligations of that investment.

A single firm demanding funds is in competition with all other firms that are acquiring capital, and the shares of stock, bonds or notes it issues to acquire those funds are competing with all other forms of securities that are available in the capital market. This is true not only for new issues, but also for existing issues that are traded among investors.

The cost of capital, as applied in regulation, is measured using a weighted average of the costs of debt, preferred stock and common stock that have been previously issued to obtain the funds that are necessary to purchase the assets needed to provide service. To apply the weighted average approach, the cost of each capital component in a firm's capital structure must be determined. The cost of debt and preferred stock are generally determined on the basis of the embedded costs of the actual outstanding amounts. The cost of equity is not contractually fixed and must be estimated.

Q. Dr. Weaver, would you please briefly explain the concept of the cost of equity?

A. Equity cost is based on an expected or future return. The cost of equity capital, unlike the cost of debt or preferred stock, is not contractually fixed at the time of issuance.

Investors in the equity market supply funds to corporate users on the basis of what they either explicitly or implicitly expect the return will be in the future and on how certain they feel that expectation will be realized. The expected return may be realized through the receipt of dividend income, appreciation of the security's market price, or some combination of both dividend income and market price appreciation.

The rate of return is determined by the sum of the future dividend income and price appreciation relative to the amount of investment required. Past returns can be used to forecast the future returns, but actual future returns will differ from those that were estimated when the investment decision was made.

Q. Please describe the risk associated with the return estimate.

A. Risk is the likelihood that the actual return may be less than the expected return. Risk, therefore, is caused by any phenomenon which may result in the actual future return being less than the return anticipated when the investment was made. The greater the likelihood that an actual return will vary on the downside from its anticipated return, the greater the risk. Risk may be caused by conditions external to the firm or from conditions that are, to some degree, within the firm's control. Some examples of external conditions are the prospective state of the economy, inflation, and capital market conditions. Internal factors include management efficiency, technology changes, liquidity, and financial structure.

In regulation, the return which is allowed should be similar to the return that is earned by other companies that have similar risk. Risk, as it applies to the cost of equity, should be considered as total risk rather than the risk that would result from the occurrence of any single factor. Risk that results from any one particular phenomenon could be offset by the occurrence of other phenomena. For example, the state of the economy may improve causing an increase in actual returns. However, if improvement in the economy was accompanied by an increasing inflation rate, the real return may remain the same, or even decrease.

Risk, by definition, stems from differences between the actual future return and the return anticipated when the investment was made. As such, it is a future phenomenon and must be estimated. Past returns to an investor are known with certainty; and therefore, there is no risk associated with their measurement. Evaluation of past data can be used to make implications concerning risk, but past measures are useful only to the extent they correspond to the risk that investors perceive to be embodied in an equity investment.

Q. Please explain how expected return and risk provide the opportunity cost principle framework for determining the cost of equity.

A. Investors consider two measures when choosing among alternative investments. The first is the anticipated or expected return for each investment. The second is risk. These two measures, expected return and risk, are combined into a framework known as the opportunity cost principle. The principle states that, for a given level of risk, investors will choose the alternative which provides the highest expected return.

The opportunity cost principle provides a model which explains a rational risk-averse investor's selection process. An investor is confronted with a large number of investments in the capital market. In order to make a rational choice among these alternatives, the investor must derive for each alternative both the expected return on investment, and the risk or likelihood that the anticipated return will not be realized. The investor will then choose the alternative that promises the highest expected return relative to the level of risk assumed.

Security prices reflect the composite behavior of all investors. If investors do not choose to purchase a particular security, that security's price will fall until its anticipated rate of return is comparable to other investment alternatives at the same risk level. In an efficient market, this process occurs very rapidly so that, market prices reflect investor expectations for return and risk.

Q. Does this same adjustment process hold for securities that have different risk levels?

A. Because investors continually apply the opportunity cost principle to market prices, securities which are perceived to have greater risk also have higher levels of expected returns. An investor requires a risk premium in the form of higher expected returns in order to assume increased risk. Risk premiums enable riskier firms to compete for investor-supplied funds in the capital market with the less risky firms. For example, stocks and bonds compete with one another for capital.

This does not imply that the higher levels of expected returns for the more risky securities will always be realized. If the expected return of a particular common stock were always realized, there would be no risk associated with that investment opportunity.

The security's return, always being realized, would be a certain return and it would have no risk premium in its cost rate. Its return or cost rate would be similar to that of a high grade bond. The more risky the security, the greater the likelihood that its actual return will differ from the return that was expected when the investment was made.

Q. Please explain the problem associated with using past data as an exact measure of the cost of equity.

A. Past returns to a security are known with certainty and there is no risk associated with their measurement. For this reason, it is not correct to use historical data as an absolute measure for the cost of equity. Historical data can provide guidance when estimating expected returns or the cost of equity. However, care must be taken to eliminate biases in the data and judgment must be used when evaluating the derived measures.

For these reasons, no precise formula exists for determining the cost of equity. The cost of equity is based upon the opportunity cost principle; and opportunity cost combines investor expectations (or investor thinking) regarding future returns - that is, future dividends and market price appreciation - and the future risk that the expectations will not be realized. As such, informed judgment is required to formulate the estimate.

Q. What technique did you use to formulate your recommendation for the cost of equity?

A. As I indicated, there is no precise method to determine the cost of equity. Equity valuation models provide information which an analyst uses to form an estimate of the cost of equity. To obtain information, I use the discounted cash flow (DCF) method, the Capital Asset Pricing Model (CAPM) and a bond yield-risk premium method.

Q. Dr. Weaver, please briefly describe the DCF technique.

A. Common stockholders receive a return on their investment through the receipt of dividend income and through increases in the market price of their investment. The DCF technique directly evaluates this return. The DCF model is derived from the premise that the market price of a share of common stock is the present value of the dividend stream during the holding period and the expected market price at the end of that same holding period. This stems directly from the opportunity cost principle. The discount rate that equates the expected dividend income and future market price to the current market price is the investor's opportunity cost. The derivation of the model for various holding periods is presented in the Attachment to this Appendix.

Q. What assumptions are required to implement the technique?

A. One assumption is required for the derivation of the DCF model. The derivation requires that the combination of dividend increases and market price appreciation occur at a constant growth rate. For example, on page 1 of the Attachment, the model is derived for a single period. The underlying assumption for this derivation is that the growth rate is constant over that single period. That is, "f," the growth variable, is the same wherever it appears in the derivation. On page 2 of the Attachment, the model is derived for two periods. In this derivation, "g," the growth variable, is the same wherever it appears and is therefore constant. On page 3 of the Attachment, the model is derived for three periods and the growth variable "h" is the same throughout the derivation and is therefore constant over the three periods.

The assumption of constant growth expectations is not intended to be a description of what has occurred in the past or of what will actually occur in the future. This assumption implies that at a given moment in time, investors have constant growth expectations regarding the future. For example, if an investor were choosing between two stocks of equal risk, he would choose to invest in the stock that he believed would afford the highest return over the holding period. At the moment the investment decision is being made, it is unlikely that the investor would segment the time horizon into several shorter time intervals and determine an expected return for each stock in each sub-interval selected and compare the several returns one to another.

A rational investor would choose to invest in the stock that has the highest expected return in the first sub-interval, and then he would reevaluate the investment alternative prior to the start of the second interval. Thus, the investor would assume a constant return over the shorter interval of time. It follows than that the assumption of constant growth is consistent with rational investor behavior.

Q. How does the constant growth assumption apply to the rate making process?

A. Constant growth must be assumed for the length of time between rate cases. For example, if a utility were to seek rate relief every two years, then its cost of equity would be reevaluated every two years as a part of the rate making process. Therefore, the growth rate need only be assumed constant for two years since it is reevaluated and may be changed after that period.

The duration of the constant growth assumption is illustrated on page 5 of the Attachment. In this example, the growth rate variable is not the same over the entire period. It is "g" for two periods and then "g*" for the next two periods. This serves to illustrate that the infinite constant growth assumption is applicable in rate making only if accompanied by the assumption that the utility being evaluated will never become involved in another rate case proceeding.

In summary, the Attachment shows that regardless of the length of time being considered, the DCF model reduces to dividend yield plus growth. However, the original formulation is the better conceptual model. That is, the cost of equity is the return on the price of common stock resulting from dividend income and market price appreciation. This model uses data obtained from the capital market and relies on the opportunity cost principle in its formulation.

Q. Are any other assumptions required when using the DCF technique?

A. No other assumptions are required in its implementation. Cost of capital witnesses sometimes regard the earnings stream to be important in estimating the growth that accrues to the firm (net income) or the growth that accrues to the investors (dividend income and market price appreciation).

Changes in the firm's earnings stream must determine market price appreciation and dividend income when the dividend payout ratio and the price-earnings ratio are constant. However, even if these ratios were not constant, the average income stream accruing to the firm would have to approximate the dividends and price appreciation earnings stream over a long period of time.

The reason that the two earnings streams must be approximately the same in the long run is as follows. If earnings are retained and invested internally at the firm's overall rate of return, future earnings will increase, causing future market price appreciation and future dividend increases. If dividends had been paid out, then additional stock must be sold to finance the same amount of investment. Assuming a constant overall rate of return, earnings on the new investment would be sufficient to provide the new stockholders the same return that is realized by the old stockholders.

In one case, investors enjoy larger future dividends and price appreciation, while in the other they enjoy more sizeable current dividends. With a constant rate of return and a stable risk structure, the present value of the increase in future dividends and price appreciation must equal the present value of the increase in current dividends.

In the short run, the two earnings streams may not be equal. It then becomes a question concerning which expected earnings stream do investors capitalize - the earnings accruing to the firm or the dividends and market price appreciation which accrues to the investors themselves. I believe that investors consider their personal income (i.e., dividends and price appreciation) to be more relevant than the firm's income and they therefore capitalize dividends and price appreciation. The growth estimate I use in the DCF model is for dividend and market price appreciation. Thus, no other assumptions are required.

Q. Dr. Weaver, what other methods are similar to the DCF method?

A. The earnings price (E-P technique) and the comparable earnings technique are similar to the DCF method. The E-P technique is sometimes called the investor's short-term capitalization rate. If there were no expected growth in earnings, it would provide a measure of investor cost of equity rates. The implied zero-growth assumption limits the information content of this measure.

The comparable earnings technique measures the return on the book value of equity. This technique has limited usefulness because it ignores the economic conditions in the capital markets where funds must be obtained, relying completely on accounting data. However, each of the three methods have similar mathematical properties.

Q. Please briefly explain the similarities between the DCF, the E-P, and the comparable earnings techniques.

A. The mathematical similarities among the three methods can be shown without the use of assumptions or without a present value model. All three equity valuation techniques begin with earnings per share (EPS) and relate EPS to either market price per share of equity, book value per share of equity, or both. This is demonstrated at the top of the next page.

METHOD:

Earnings Price	DCF	Comparable Earnings

START WITH EPS FOR EACH METHOD:

EPS	EPS	EPS

DIVIDE EPS BY MARKET PRICE OR BOOK VALUE OR SPLIT INTO DIVIDENDS AND RETAINED INCOME COMPONENTS AND DIVIDE BY BOTH:

$$\frac{\text{EPS}}{\text{Market Price Per Share}} \qquad \frac{\text{Dividends}}{\text{Market Price Per Share}} + \frac{\text{Retained Income}}{\text{Book Value Per Share}} \qquad \frac{\text{EPS}}{\text{Book Value Per Share}}$$

Please notice that the Earnings-Price Model is a ratio of earnings per share to market price per share. The comparable earnings ratio relates earnings per share to book value per share. The DCF method is a combination of the previous methods. For the DCF method, EPS is split into dividends and retained income. The dividend is related to the market price - as a yield to the investor. The retained income is related to book value - as a return on the book equity of the firm. That is, retained income is invested in new assets and is assumed to earn a return similar to the return being earned by the firm's other assets. This retained income provides for growth to investors while the dividend income provides a current yield.

Q. Dr. Weaver, you have indicated the relationship between the earnings-price, DCF, and comparable earnings techniques. Since the techniques are related, will the results from applying the three techniques be equal?

A. The results of the three techniques will be equal if one assumes that a company's market price for a share of stock is also equal to the book value per share. In this situation, the earnings-Price, DCF, and Comparable Earnings techniques will yield identical results. The reason is quite simple. Each of the respective numerators is earnings per share or dividends and retained income which sums to earnings per share. When the market price is equal to book value, each denominator for the three techniques is also the same.

If the market price were equal to the book value, the analyst would no longer have three techniques to utilize for the evaluation. However, this equality would seldom occur. Differences between the market price and book value therefore permit all three methods to be used in developing a recommended return on equity.

There is no reason why the market price should equal the book value of a firm's stock. A simple example is useful for illustrating this fact. Assume there existed two companies that are identical in every respect except for the accounting methodologies employed. The different accounting methods will cause the companies to have different book values of equity. If the companies are identical, the market price of the common stock should be the same. The different accounting methodologies would, however, cause the book values to differ.

Q. How did you formulate your estimate for the growth variable used in the DCF model?

A. I use a number of different methods to formulate an estimate of growth for use in the DCF model. I do this to obtain information to augment my analysis. I use a variety of sources for estimating growth because the growth estimate in the DCF model represents the rate of increase for dividends and market price between this and the Company's next rate case proceeding before the Commission. There is no single method that provides "the answer."

One way is to use analysts' forecasts for future growth in earning per share, dividends, or book value. Two sources for these forecasts are Value Line and I/B/E/S. Value Line analysts forecast the three to five year growth in earnings, dividends, and book value for each of the approximately 1,700 which they follow. I/B/E/S surveys the investment banking firms research departments to obtain the estimates that are being made by the professional security analysts. Academic studies have shown that analysts' forecast provide reasonably good estimates for use in the DCF model.

Past data may also be used to estimate the future growth rate. Judgement must be exercised when using past data because past events are not perfect predictors of future events. For this reason, several data items should be used to provide insight on the appropriate values for formulating this estimate.

The growth rate of past dividends over some representative period may provide useful information because some investors may use the technique in estimating growth. The appropriate use of this method, however, requires discretion since dividends are declared by the board of directors and may not represent the real growth rate. I will use this method in conjunction with other methods for estimating growth.

The compound growth rate in earnings per share is another estimator which is frequently used. However, only a portion of earnings per share is retained and reinvested in new assets to facilitate future growth. In the case of utilities, the majority of earnings per share is paid out in the form of dividends. The use of the growth rate in earnings per share is based on the assumption that the P/E ratio and dividend payout ratio are constant.

The compound rate of growth in book value per share is also used to estimate growth. The growth in book value represents the amount of earnings per share that are retained and plowed back into the firm and, in this respect, is similar to the growth in EPS. However, this measure generally produces a lower growth estimate than the growth rate in EPS because growth of book value only measures the portion that is retained. A weakness regarding the use of this measure is that no assumption is made concerning the earnings capability of the assets that are associated with the change in book value.

Another measure, the earnings retention ratio multiplied by the return on book value of equity is the estimator for sustainable growth. The portion of earnings that is retained and invested in new assets provides the growth for the equity holders in future periods. The new assets can reasonably be expected to provide a return that is close to the rate that existing assets are currently earning. The return on book value of equity represents the return on assets of the firm after the effect of debt leverage.

The product of the earnings retention ratio times the return on book value of equity is both a logically correct and theoretically sound estimator of future earnings growth. A share of stock represents a residual claim on the firm's earnings stream. Growth is a result of the claim's proportion of earnings increasing, the earnings stream increasing, or some combination of the proportionate claim and earnings stream increasing.

Growth of the proportionate claim or earnings stream can occur in six ways. These are: (1) the firm is able to continuously increase the efficiency of its asset utilization; (2) the firm issues new shares at a market price that is greater than the book value of its equity; (3) the firm is able to purchase existing outstanding stock at a price that is less than the firm's book value of its equity; (4) the firm is able to sell some of its assets for a price that exceeds the respective book value of those assets; (5) the firm employs more leverage; or (6) the firm is able to retain income and invest in new assets that have a return that is greater than, or equal to, the return currently being earned on assets. This sixth method is the only sustainable method for accomplishing growth. The BxR method only captures one way in growth can occur and it ignores these other factors which, although they are not sustainable, are sources of growth.

The method for formulating the growth estimate, the earnings retention ratio times the return on equity, can mathematically be reduced to retained income divided by book value per share. This ratio was used in my previous explanation of the similarities among the earnings-price and DCF methods. This mathematical reduction is as follows:

$$\text{Earnings Retention Ratio:} \quad 1 - \frac{DIV}{EPS}$$

Determining a common denominator and subtracting:

$$1 - \frac{DIV}{EPS} = \frac{EPS}{EPS} - \frac{DIV}{EPS} = \frac{EPS\text{-}DIV}{EPS}$$

Thus retained income can be substituted for EPS-DIV:

$$EPS\text{-}DIV = \text{Retained Income}$$

Multiplying the Earnings Retention Ratio times the Return on Equity provides the following results:

$$\frac{\text{Retained Income}}{EPS} \times \frac{EPS}{\text{Equity Book Value}}$$

Cancellation of EPS results in the following:

$$\frac{\text{Retained Income}}{\text{Equity Book Value}}$$

Therefore, the growth rate estimated by using the earnings retention ratio times the return on equity is reduced to the ratio relating the retained income of the firm to the book value of equity.

Q. Since the earnings-price and DCF methods have these mathematical similarities, what are the differences between the methods?

A. The chief difference in the three methods is that the earnings price method is simply a mathematical ratio. The DCF method, while being a mathematical ratio, has been derived from a foundation that simulates investor behavior using a present value analysis.

The DCF method is therefore derived from a theoretical foundation, which justifies its analytical use to evaluate the cost of equity.

CAPITAL ASSET PRICING MODEL

Q. You indicated you use CAPM to also obtain information for estimating the cost of equity. Would you please explain the CAPM?

A. Yes. The CAPM presumes that investors are risk averse. More risky securities must provide a higher expected return or investors would have no reason to include them in their investment portfolios.

This higher-risk/higher-expected-return principle permits the cost of equity to be split into two components: (1) a default-free rate, and (2) a risk premium. The default-free rate is assumed to be the same for all securities. The risk premium is larger for more risky securities and smaller for less risky securities.

According to CAPM, the amount of risk premium can be determined in ;two steps. The first requires that the average risk premium for the equity market be estimated. In the second step, this average risk premium must be adjusted either upward or downward, depending upon whether the security being considered is more or less risky than the average.

The adjustment is made by multiplying the average risk premium by beta. Beta is a measure of the risk of an individual security relative to an average security. A security that has the same risk premium as an average security would have a beta equal to one.

Less risky securities have betas less than one and more risky securities have betas greater than one.

The CAPM is formulated as:

$K_i = R_f + B(K_m - R_f)$ **where:**

K_I = The expected return on security I;
R_f = The expected default-free rate;
K_m = The expected return on an average security;
$K_m - R_f$ = The risk premium for an average security; and
B = Beta

Q. **What data are required to implement the CAPM?**

A. Three data elements are required to implement the CAPM. These are the expected default-free rate; the expected return on an average security; and beta.

Q. **What are the data sources for these data?**

A. A short- or a long-term bond rate is generally used as a proxy for the expected default-free rate. A short-term rate is preferred because it is more independent to the market return rate -- that is, there is less covariance.

The variable to use as a proxy for the expected return on an average security is more difficult to determine. Some of the variables that are used include a long-term historical average risk premium, estimates made from data provided by conventional financial information sources such as Value Line, or estimates that were made in published studies by brokerage houses. An estimate of beta can be obtained from numerous sources but these can also vary considerably, depending on the source.

Q. **How does the use of data from different sources affect the validity of the CAPM**

results?

A. Obviously, using different data will give different results. For this reason, several estimates should be made using data from different sources or different combinations of data. This will result in a range of solutions being determined. Since different investors will use different methods and data to make their buy and sell decisions, this will reflect the market as a whole and provide a range for the cost of equity. The true cost of equity will most likely be somewhere within the bounds of that range.

BOND-YIELD-RISK-PREMIUM METHOD

Q. Please explain the bond-yield-risk-premium method.

A. Yes. The bond-yield-risk-premium method calls for simply adding a risk premium to a bond yield. The risk premium is the difference between the cost of debt at a certain risk level versus the cost of equity at a different risk level. The risk premium is difficult and risk premiums change as investor's risk aversion change. When there are periods of economic optimism for future economic conditions, risk premiums tend to become small. When there is economic uncertainty and pessimissim, risk premiums are larger.

One way to estimate a risk premium is to determine what the total return on a company's common stock has been relative to some particular market bond yield. Another way is to survey analysts to determine what their estimates are. A weakness with this method is that the premiums change over time and surveys become out of date.

Q. How did you implement this method?

A. I select a recent time period which in my judgement reflects the expected economic conditions for the near-term future. I then determine the realized return on a group of companies that have similar risk to the company being analyzed. I used the comparable companies that I used for the DCF analysis and CAPM analysis. I determine the realized return for all possible one-year holding periods during the most recent ten-year time period. I compared all of the possible one-year holding period returns from the group of comparable companies with similar holding period yields on ten-year government bonds. e realized The risk premium is the difference between the average stock returns and the average bond return. I add this risk premium to the forecasted yields on the ten year government bonds to obtain an estimate of the cost of equity.

Q. What does the sum of the risk premium and bond yield represent?

A. The government bond yield represents a default free rate of return that contains only a premium for expected inflation and marketability. The stock risk premium represents the additional return that is required for the risk of the similar public utility companies. The sum of the two represents, according to this method, the return on equity.

Q. Dr. Weaver, did you use the methods you have discussed here in your testimony?

A. Yes. I did.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Delta Natural Gas Company, Inc.	)	
Experimental Alternative	)	Case No. 99-046
Regulation Plan	)	

EXHIBIT OF CARL G.K. WEAVER
APPEARING ON BEHALF OF THE OFFICE OF
THE ATTORNEY GENERAL FOR THE COMMONWEALTH OF KENTUCKY
UTILITY AND RATE INTERVENTION DIVISION

July 30, 1999

Exhibit ________
Carl G. K. Weaver
Schedule 1

Delta Natural Gas Company, Inc.
Total Assets
23 Gas Distribution Companies Listed in Value Line
(thousands of dollars)

Company Name	Fiscal Year Ending	1998	1997	Percentage Increase 1997 to 1998
Providence Energy Corp.	Sept. 30	253,410	255,510	(0.4)
Cascade Natural Gas Corp.	Sept. 30	311,511	307,703	0.6
CTG Resources*	Sept. 30	459,181	444,373	1.7
Conn. Energy Corp.	Sept. 30	459,401	424,281	4.1
Indiana Energy, Inc.	Sept. 30	712,350	690,845	1.5
South Jersey Industries, Inc.	Dec. 31	748,095	670,601	5.6
Laclede Gas Co.	Sept. 30	771,147	720,710	3.4
NUI Corp.	Sept. 30	776,847	803,665	(1.7)
New Jersey Resources Corp.	Sept. 30	943,018	879,061	3.6
Energen Corp.	Sept. 30	993,455	919,797	3.9
WICOR, Inc.	Dec. 31	1,015,196	1,031,332	(0.8)
Atmos Energy Corp.	Sept. 30	1,141,390	1,088,311	2.4
Piedmont Natural Gas Co.	Oct. 31	1,162,844	1,098,156	2.9
Northwest Natural Gas Co.	Dec. 31	1,191,736	1,111,617	3.5
Washington Gas Light, Co.	Sept. 30	1,682,433	1,552,032	4.1
Southwest Gas Corp.	Dec. 31	1,830,694	1,769,059	1.7
Peoples Energy Corp.	Sept. 30	1,904,500	1,820,805	2.3
AGL Resources, Inc.	Sept. 30	1,981,800	1,925,500	1.5
UGI Corp.	Sept. 30	2,074,600	2,151,700	(1.8)
NICOR Inc.	Dec. 31	2,364,600	2,394,600	(0.6)
ONEOK Inc.	Aug. 31	2,422,487	1,237,407	39.9
Keyspan Energy Corp.*	Sept. 30	2,497,190	228,960	*
MCN Corp.	Dec. 31	4,392,486	4,329,461	0.7
Delta Natural Gas, Co.	**June 30**	**102,867**	**96,681**	**3.1**

Source: Compact Disclosure
* Keyspan formed by the merger of Brooklyn Union and Long Island Lighting Co. in May, 1998.
Note: Sorted by 1998 Total Assets.

Exhibit ________
Carl G. K. Weaver
Schedule 2

Delta Natural Gas Company, Inc.
Net Sales / Total Assets
23 Gas Distribution Companies Listed in Value Line

Company Name	1998	1997	1996	1996-98 Average
Northwest Natural Gas Co.	35%	32%	24%	30%
Southwest Gas Corp.	50%	41%	41%	44%
MCN Corp.	43%	48%	52%	48%
South Jersey Industries, Inc.	60%	52%	54%	55%
Cascade Natural Gas Corp.	61%	64%	43%	56%
Energen Corp.	51%	49%	70%	57%
Conn. Energy Corp.	53%	59%	65%	59%
Keyspan Energy Corp.*	*	59%	63%	61%
Washington Gas Light, Co.	62%	68%	66%	65%
Peoples Energy Corp.	60%	70%	67%	66%
CTG Resources	62%	69%	67%	66%
Piedmont Natural Cas Co.	66%	71%	64%	67%
AGL Resources, Inc.	68%	67%	67%	67%
UGI Corp.	69%	76%	73%	73%
New Jersey Resources Corp.	75%	79%	64%	73%
Indiana Energy, Inc.	65%	77%	78%	73%
NICOR Inc.	62%	83%	76%	74%
Laclede Gas Co.	71%	84%	81%	79%
Atmos Energy Corp.	74%	83%	88%	82%
NUI Corp.	107%	76%	69%	84%
Providence Energy Corp.	87%	86%	86%	86%
ONEOK Inc.	76%	94%	100%	90%
WICOR, Inc.	93%	99%	98%	97%
Delta Natural Gas, Co.	**43%**	**44%**	**45%**	**44%**

Source: Compact Disclosure
Note: Sorted by Average Net Sales/Total Assets Ratios
* Keyspan formed in May 1958 by merger of Brooklyn Union and Long Island Lighting

Exhibit ________
Carl G. K. Weaver
Schedule 3

Delta Natural Gas Company, Inc.

Common Equity Ratio

23 Gas Distribution Companies Listed in Value Line

Company Name	1998	1997	1996	1996-98 Average
UGI Corp.	28.7	30.0	30.0	29.6
Southwest Gas Corp.	35.6	31.5	34.4	33.8
MCN Corp.	30.9	39.9	35.2	35.3
New Jersey Resources Corp.	45.6	47.1	45.8	46.2
NUI Corp.	48.4	47.8	42.7	46.3
South Jersey Industries, Inc.	42.5	44.8	53.2	46.8
AGL Resources, Inc.	47.1	45.9	48.9	47.3
Cascade Natural Gas Corp.	48.7	46.5	50.0	48.4
Energen Corp.	46.9	51.9	49.1	49.3
CTG Resources	36.3	57.0	55.2	49.5
Northwest Natural Gas Co.	51.5	49.0	52.8	51.1
Providence Energy Corp.	51.0	52.1	50.6	51.2
Conn. Energy Corp.	54.1	51.9	49.9	52.0
Piedmont Natural Cas Co.	55.3	52.4	49.7	52.5
Atmos Energy Corp.	48.2	51.9	58.5	52.9
Keyspan Energy Corp.*	60.0	56.5	55.8	57.4
NICOR Inc.	57.0	57.2	58.1	57.4
Washington Gas Light, Co.	57.1	56.2	59.4	57.6
Peoples Energy Corp.	58.9	57.6	56.4	57.6
Laclede Gas Co.	58.6	61.6	57.1	59.1
Indiana Energy, Inc.	62.5	65.0	62.5	63.3
ONEOK Inc.	78.9	58.5	55.1	64.2
WICOR, Inc.	73.0	72.3	68.5	71.3
Delta Natural Gas, Co.	~~**36.1**~~ 36.2	~~**43.6**~~ ~~44.7~~ 42	**35.7**	**38.5**

Source: Value Line (ONEOK from Compact Disclosure and Delta from Annual Reports)

Note: Sorted by Average Net Sales/Total Assets Ratios

* Keyspan formed in May 1958 by merger of Brooklyn Union and Long Island Lighting

Exhibit ________
Carl G. K. Weaver
Schedule 4

Delta Natural Gas Company, Inc.

Total Liabilities/ Total Assets

23 Gas Distribution Companies Listed in Value Line

Company Name	1998	1997	1996	1996-98 Average
NUI Corp.	71%	73%	74%	73%
Southwest Gas Corp.	71%	75%	72%	73%
South Jersey Industries, Inc.	72%	69%	73%	71%
NICOR Inc.	68%	69%	70%	69%
UGI Corp.	70%	69%	67%	69%
Atmos Energy Corp.	67%	70%	67%	68%
MCN Corp.	70%	61%	73%	68%
Energen Corp.	67%	67%	67%	67%
CTG Resources	73%	62%	64%	66%
New Jersey Resources Corp.	67%	66%	66%	66%
Laclede Gas Co.	66%	65%	65%	65%
AGL Resources, Inc.	63%	64%	65%	64%
Conn. Energy Corp.	61%	66%	65%	64%
Providence Energy Corp.	63%	64%	64%	64%
Piedmont Natural Cas Co.	61%	62%	64%	62%
WICOR, Inc.	60%	62%	65%	62%
Northwest Natural Gas Co.	61%	64%	61%	62%
Cascade Natural Gas Corp.	62%	62%	61%	62%
Washington Gas Light, Co.	62%	60%	60%	61%
ONEOK Inc.	52%	63%	65%	60%
Keyspan Energy Corp.*		58%	57%	58%
Indiana Energy, Inc.	57%	58%	57%	57%
Peoples Energy Corp.	34%	61%	62%	52%
Delta Natural Gas, Co.	**71%**	**70%**	**71%**	**71%**

Source: Compact Disclosure

Note: Sorted by Average Net Sales/Total Assets Ratios

* Keyspan formed in May 1958 by merger of Brooklyn Union and Long Island Lighting

Exhibit ________
Carl G. K. Weaver
Schedule 5

Selected Comparable Companies
Summary

Company	1998 Total Assets	Percentage Increase 1997-1998	1996-98 Avg Net Sales to Total Assets	1996-98 Avg Common Equity Ratio	1996-98 Avg. Tot. Liab. to Total Assets
Cascade	311,511	0.6	0.56	48.4%	62%
Conn. Eng.	459,401	4.1	0.59	52.0%	64%
CTG Res.	459,181	1.7	0.66	49.5%	66%
Energen	993,455	3.9	0.57	49.3%	67%
S Jersey Ind.	748,095	5.6	0.55	46.8%	71%
Average	594,329	3.2	0.59	49.2%	66%
Delta	102,867	3.1	0.44	38.5%	71%

Source: Schedules 1 to 4 of this Exhibit.

Exhibit ________
Carl G. K. Weaver
Schedule 6

Selected Comparable Companies
1998 Capitalization

Company	Short-term Debt	Long-term Debt *	Preferred Stock	Common Equity	Total
Cascade	6,929	120,650	6,408	117,836	251,823
Conn. Eng.	22,400	151,328	0	177,153	350,881
CTG Res.	2,000	221,585	879	124,276	348,740
Energen	153,000	379,991	0	329,249	862,240
S. Jersey Ind.	97,000	203,586	37,134	206,368	544,088
Average	56,266	215,428	8,884	190,976	471,554
Delta	1,875	54,402	0	29,810	86,088

Source: Compact Disclosure and 1998 Shareholders Annual Report for Delta
* Includes current portion of long-term debt.

Exhibit ________
Carl G. K. Weaver
Schedule 7

Selected Comparable Companies
1998 Capital Structure

Company	Short-term Debt	Long-term Debt	Preferred Stock	Common Equity	Total
Cascade	2.8%	47.9%	2.5%	46.8%	100.0%
Conn. Eng.	6.4%	43.1%	-	50.5%	100.0%
CTG Res.	0.6%	63.5%	0.3%	35.6%	100.0%
Energen	17.7%	44.1%	-	38.2%	100.0%
S. Jersey Ind.	17.8%	37.4%	6.8%	37.9%	100.0%
Average	9.1%	47.2%	1.9%	41.8%	100.0%
Delta	2.2%	63.2%	-	34.6%	100.0%

Source: Schedule 6

Exhibit ________
Carl G. K. Weaver
Schedule 8

Cash Flow Analysis
Gas Distribution Companies
Cascade Natural Gas Corp.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	46	38,564	19,305
Cash Flow from Investing Activities	(21,166)	(22,918)	(22,042)
Cash Flow from Financing Activities	23,739	(16,470)	3,635
Change in Cash Flow	2,619	(824)	898
Cash Flow Coverage of Interest	1.005	5.02	3.01
Cash Flow Coverage of Total Dividends	0.005	3.66	1.83
Cash flow Coverage of Investing Activities	0.002	1.68	0.84
Quality of Earnings	0.004	4.04	2.02

Source: May 1999 Compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 9

Cash Flow Analysis
Gas Distribution Companies
Connecticut Energy Corp.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	28,818	27,781	28,300
Cash Flow from Investing Activities	(29,439)	(36,752)	(33,096)
Cash Flow from Financing Activities	2,144	12,418	7,281
Change in Cash Flow	1,523	3,447	2,485
Cash Flow Coverage of Interest	3.11	3.11	3.11
Cash Flow Coverage of Total Dividends	2.40	2.04	2.22
Cash flow Coverage of Investing Activities	0.98	0.76	0.87
Quality of Earnings	1.75	1.46	1.61

Source: May 1999 Compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 10

Cash Flow Analysis
Gas Distribution Companies
CTG Resources Inc.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	29,554	27,091	28,323
Cash Flow from Investing Activities	(22,778)	(36,159)	(29,469)
Cash Flow from Financing Activities	(10,833)	5,874	(2,480)
Change in Cash Flow	(4,057)	(3,194)	(3,626)
Cash Flow Coverage of Interest	3.30	2.70	3.00
Cash Flow Coverage of Total Dividends	1.83	3.13	2.48
Cash flow Coverage of Investing Activities	1.30	0.75	1.02
Quality of Earnings	1.73	1.78	1.76

Source: May 1999 Compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 11

Cash Flow Analysis
Gas Distribution Companies
Energen Corp.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	63,099	123,623	93,361
Cash Flow from Investing Activities	(279,846)	(166,308)	(223,077)
Cash Flow from Financing Activities	310,848	40,514	175,681
Change in Cash Flow	94,101	(2,171)	45,965
Cash Flow Coverage of Interest	3.75	5.12	4.44
Cash Flow Coverage of Total Dividends	4.12	6.80	5.46
Cash flow Coverage of Investing Activities	0.23	0.74	0.48
Quality of Earnings	2.18	3.41	2.79

Source: May 1999 Compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 12

Cash Flow Analysis
Gas Distribution Companies
South Jersey Industries, Inc.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	39,953	7,360	23,657
Cash Flow from Investing Activities	(57,684)	(67,138)	(62,411)
Cash Flow from Financing Activities	(16,085)	53,328	18,622
Change in Cash Flow	(33,816)	(6,450)	(20,133)
Cash Flow Coverage of Interest	3.25	1.39	2.32
Cash Flow Coverage of Total Dividends	2.58	0.47	1.53
Cash flow Coverage of Investing Activities	0.69	0.11	0.40
Quality of Earnings	2.53	0.67	1.60

Source: May 1999 Compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 13

Cash Flow Analysis
Gas Distribution Companies
Delta Natural Gas Company, Inc.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	6,209	8,922	7,566
Cash Flow from Investing Activities	(16,649)	(11,194)	(13,922)
Cash Flow from Financing Activities	10,769	1,910	6,340
Change in Cash Flow	329	(362)	(16)
Cash Flow Coverage of Interest	3.06	3.08	3.07
Cash Flow Coverage of Total Dividends	2.34	3.32	2.83
Cash flow Coverage of Investing Activities	0.37	0.80	0.58
Quality of Earnings	3.60	3.64	3.62

Source: May 1999 Compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 14

Cash Flow Analysis
Selected Comparable Companies
Summary

	Cash Flow Coverage of:			
	Interest	Dividends	Investing Activities	Quality of Earnings
Cascade	3.01	1.83	0.84	2.02
Conn. Eng.	3.11	2.22	0.87	1.61
CTG Res.	3.00	2.48	1.02	1.76
Energen	4.44	5.46	0.48	2.79
S Jersey Ind.	2.32	1.53	0.40	1.60
Average	3.18	2.70	0.72	1.96
Delta	3.07	2.83	0.58	3.62

Source: Schedules 8 to 13 of this Exhibit.

Exhibit________
Carl G. K. Weaver
Schedule 15

Delta Natural Gas Company, Inc.
Standard & Poor's Measures
Selected Comparable Companies

Company Name	Risk	Beta	Relative Strength Rank
Cascade	Low	0.02	0.55
Conn. Eng.	Low	0.23	0.91
CTG Resources	Low	0.69	0.73
Energen	Low	0.07	0.79
S. Jersey Ind.	Low	0.52	0.43
Average	-	0.31	0.68
Delta	Low	0.02	0.32

Source: Standard & Poor's Stock Reports, May 8, 1999.

Exhibit_______
Carl G. K. Weaver
Schedule 16

Delta Natural Gas Company, Inc.
Value Line Measures
Selected Comparable Companies

Company Name	Safety Rating	Beta
Cascade	3	0.55
Conn. Eng.	2	0.60
CTG Resources	2	0.55
Energen	2	0.80
S. Jersey Ind.	2	0.50
Average	2	0.60

Source: Value Line, March 26, 1999

Exhibit ________
Carl G. K. Weaver
Schedule 17

Historical
Economic Indicators
Annual Average Real Rate of Change

Year	Real GDP % Change (1)	CPI % Change (2)
1976	4.9	5.8
1977	4.5	6.5
1978	4.8	7.7
1979	2.5	11.3
1980	-0.5	13.5
1981	1.8	10.3
1982	-2.2	6.2
1983	3.9	3.2
1984	6.2	4.3
1985	3.2	3.6
1986	2.9	1.9
1987	3.1	3.6
1988	3.9	4.1
1989	2.5	4.8
1990	1.2	5.4
1991	-0.6	4.2
1992	2.3	3.0
1993	2.3	3.0
1994	3.5	2.6
1995	2.3	2.8
1996	3.4	2.9
1997	3.9	2.3
1998	3.9	1.6

Sources: (1) 1976 - 1991 from Survey of Current Business, March 1996. 1992 through 1998 from Value Line Selection and Opinion, May 28, 1999, p. 5537.

(2) For all Urban Consumers, Monthly Labor Review. 1992 - 1998 from Value Line Selection and Opinion, May 28, 1999, p. 5537.

Exhibit ________
Carl G. K. Weaver
Schedule 18

Real GDP and CPI
Percentage Change
Actual versus Forecast

		Real GDP	CPI All Urban Consumers
Actual:			
	1994	3.5	2.6
	1995	2.3	2.8
	1996	3.4	2.9
	1997	3.9	2.3
	1998	3.9	1.6
Forecast:			
	1999	*3.8*	*2.8*
	2000	*2.3*	*2.5*
	2001	*2.5*	*2.5*
	2002	*2.7*	*2.6*
	2003	*2.8*	*2.7*

Source: Value Line Selection and Opinion, May 28, 1999
page 5537.

Exhibit ________
Carl G. K. Weaver
Schedule 19

Moody's Public Utility Bond Yields
Annual Average for 1980 - 1998
Monthly January - May 1999

	Year	Aaa	Aa	A	Baa
	1980	12.30	13.00	13.34	13.95
	1981	14.64	15.30	15.95	16.60
	1982	14.22	14.79	15.86	16.45
	1983	12.52	12.83	13.66	14.20
	1984	12.72	13.66	14.03	14.53
	1985	11.68	12.06	12.47	12.96
	1986	8.92	9.30	9.58	10.00
	1987	9.52	9.77	10.10	10.53
	1988	10.05	10.26	10.49	11.00
	1989	9.32	9.56	9.77	9.97
	1990	9.45	9.65	9.86	10.06
	1991	8.85	9.09	9.36	9.55
	1992	8.19	8.55	8.69	8.86
	1993	7.29	7.44	7.59	7.91
	1994	8.07	8.21	8.31	8.63
	1995	7.68	7.77	7.89	8.29
	1996	7.49	7.57	7.75	8.17
	1997	7.62	7.75	7.79	8.34
	1998	6.76	6.84	6.76	7.20
Jan	1999	6.41	6.82	6.97	7.30
Feb	1999	6.56	6.94	7.09	7.41
Mar	1999	6.78	7.11	7.26	7.55
Apr	1999	6.80	7.11	7.22	7.51
May	1999	7.09	7.38	7.47	7.74

Sources: Moody's 1995 Public Utility Manual ; 1998 is the average of the high/low rates; and the monthly rates are from Moody's Credit Survey, June 7, 1999, p. 55.

Exhibit ________
Carl G. K. Weaver
Schedule 20

Comparative Interest Rates
Actual versus Forecast

		3-month T-bills	10-year T-bonds
Actual:			
	1994	4.27	7.41
	1995	5.51	6.94
	1996	5.02	6.80
	1997	5.07	6.67
	1998	4.82	5.69
Forecast:			
	1999	*4.6*	*5.6*
	2000	*5.0*	*5.9*
	2001	*4.6*	*5.5*
	2002	*4.5*	*5.4*
	2003	*4.5*	*5.4*

Sources: Actual data from Standard & Poor's Statistical Reports.
Forecast data from Congressional Budget Office, The Economic Outlook, An Update, July 1, 1999, Table 2, Pages 6 & 7 of 24.

Exhibit ________
Carl G. K. Weaver
Schedule 21

Delta
Historical Growth Rates

Company Name	Value Line EPS	Value Line DPS	Value Line BVS
Cascade	5.0%	0.5%	3.0%
Conn. Eng.	3.0%	1.5%	3.5%
CTG Res.	1.0%	nil	3.0%
Energen	5.5%	5.0%	7.0%
S. Jersey Ind.	2.5%	1.5%	2.5%
Average	3.4%	1.7%	3.8%
Delta*	-0.30%	0.70%	0.50%

Source: Value Line dated March 26, 1999; Annual Rates, past 10 years.

* Delta calculated from the 1998-98 data reported in S&P Stock Reports.

Exhibit ________
Carl G. K. Weaver
Schedule 22

Delta

I/B/E/S and Value Line
Growth Rate Forecasts

Company Name	I/B/E/S EPS	Value Line EPS	Value Line DPS	Value Line BVS
Cascade	3.5%	9.5%	0.5%	4.5%
Conn. Eng.	7.2%	4.0%	3.5%	4.0%
CTG Resources	5.5%	6.6%	-2.0%	4.0%
Energen	7.2%	9.0%	3.5%	10.0%
S. Jersey Ind.	4.0%	5.0%	1.5%	4.0%
Average	5.5%	6.8%	1.4%	5.3%
Delta	3.5%			

Source: Compact Disclosure, May, 1999; and Value Line from March 26, 1999,
Annual Rates, estimated '96-'98 to '02-'04.

Exhibit ________
Carl G. K. Weaver
Schedule 23

Delta
Stock Prices and Dividend Yield

Company Name:	Cascade	Conn. Energy	CTG Resources	Energen	South Jersey Industries	Delta
Date	Closing Stock Prices					
06/24/99	18.000	38.688	32.500	18.500	27.188	16.750
06/25/99	17.875	38.688	33.500	18.688	27.063	16.875
06/28/99	18.250	38.938	34.000	18.688	27.375	16.875
06/29/99	18.250	38.750	35.625	18.563	27.500	16.875
06/30/99	19.000	38.563	36.375	18.625	28.313	16.625
07/01/99	18.688	38.438	36.938	18.938	28.938	16.688
07/02/99	18.375	38.188	36.938	19.188	29.125	16.875
07/06/99	18.125	38.438	36.500	19.063	29.313	16.875
07/07/99	18.188	38.688	36.688	18.938	29.438	16.875
07/08/99	17.938	38.875	36.688	19.000	29.625	16.750
Avg. Prices	18.269	38.625	35.575	18.819	28.388	16.806
Dividend Rate	0.960	1.360	1.040	0.640	1.440	1.12
Dividend Yields	5.25%	3.52%	2.92%	3.40%	5.07%	6.66%
Selected Companies Avg. Div. Yield:			4.03%			

Source: YAHOO! Finance, Historical Quotes, July 9, 1999; the Dividend Rate is the latest quarterly dividend multiplied times 4.

Exhibit ________
Carl G. K. Weaver
Schedule 24

Delta
Selected Comparable Companies
Discounted Cash Flow Analysis

Source For Estimated Growth	Growth Rates	Dividend Yield	Growth Adjusted Dividend Yield	DCF Estimated Cost of Equity
Forecasts				
I/B/E/S	5.5%	4.03%	4.25%	**9.75%**
VL - EPS	6.8%	4.03%	4.30%	**11.10%**
VL - DPS	1.4%	4.03%	4.09%	**5.49%**
VL - BVS	5.3%	4.03%	4.24%	**9.54%**
Average of estimates using growth rate forecasts:				**8.97%**
Average excluding VL-DPS growth forecasts:				**10.13%**
Historical				
EPS	3.4%	4.03%	4.17%	**7.57%**
DPS	1.7%	4.03%	4.10%	**5.80%**
BVS	3.8%	4.03%	4.18%	**7.98%**
Average of estimates using historical growth rates:				**7.12%**

Exhibit ________
Carl G. K. Weaver
Schedule 25

Delta Natural Gas Company, Inc.
Selected Comparable Companies
Capital Asset Pricing Model Analysis

Sources			Risk Free Rate		Beta	Market Return		CAPM Estimated Cost of Equity
Rf	*Beta*	*Km*						
Long-term Current	S&P	S&P 500	6.30%	(1)	0.31	15.5%	(7)	**9.15%**
Long-term Current	Value Line	S&P 500	6.30%		0.60	15.5%		**11.82%**
Long-term Current	S&P	Value Line	6.30%		0.31	12.5%	(8)	**8.22%**
Long-term Current	Value Line	Value Line	6.30%		0.60	12.5%		**10.02%**
Long-term Forecast	S&P	S&P 500	5.75%	(2)	0.31	15.5%		**8.77%**
Long-term Forecast	Value Line	S&P 500	5.75%		0.60	15.5%		**11.60%**
Long-term Forecast	S&P	Value Line	5.75%		0.31	12.5%		**7.84%**
Long-term Forecast	Value Line	Value Line	5.75%		0.60	12.5%		**9.80%**
Long-term Projected	S&P	S&P 500	5.40%	(3)	0.31	15.5%		**8.53%**
Long-term Projected	Value Line	S&P 500	5.40%		0.60	15.5%		**11.46%**
Long-term Projected	S&P	Value Line	5.40%		0.31	12.5%		**7.60%**
Long-term Projected	Value Line	Value Line	5.40%		0.60	12.5%		**9.66%**
Short-term Current	S&P	S&P 500	4.80%	(4)	0.31	15.5%		**8.12%**
Short-term Current	Value Line	S&P 500	4.80%		0.60	15.5%		**11.22%**
Short-term Current	S&P	Value Line	4.80%		0.31	12.5%		**7.19%**
Short-term Current	Value Line	Value Line	4.80%		0.60	12.5%		**9.42%**
Short-term Forecast	S&P	S&P 500	4.80%	(5)	0.31	15.5%		**8.12%**
Short-term Forecast	Value Line	S&P 500	4.80%		0.60	15.5%		**11.22%**
Short-term Forecast	S&P	Value Line	4.80%		0.31	12.5%		**7.19%**
Short-term Forecast	Value Line	Value Line	4.80%		0.60	12.5%		**9.42%**
Short-term Projected	S&P	S&P 500	4.50%	(6)	0.31	15.5%		**7.91%**
Short-term Projected	Value Line	S&P 500	4.50%		0.60	15.5%		**11.10%**
Short-term Projected	S&P	Value Line	4.50%		0.31	12.5%		**6.98%**
Short-term Projected	Value Line	Value Line	4.50%		0.60	12.5%		**9.30%**
Average of CAPM Analysis								**9.24%**

Notes: See next page

Notes to CAPM analysis

1. The 6.30% risk free rate is the average of the June 28-July 1, 1999 Composite (over ten year) rates that were reported in the Federal Reserve Statistical Release H.15, Selected Interest Rates, Release Date 7/2/99, page 2 of 3.

2. The 5.75% risk free rate is the long-term forecasted 1999 and 2000 10-year Treasury Note rate from The Economic Outlook, An Update published 7/1/99 by the Congressional Budget Office, p. 5 of 24.

3. The 5.40% risk free rate is the long-term projected 2001-2009 10-year Treasury Note rate from The Economic Outlook, An Update published 7/1/99 by the Congressional Budget Office, p. 7 of 24.

4. The 4.80% risk free rate is the 3-month constant maturity Treasury Bill rate for June 28-July 1, 1999 reported in the Federal Reserve Statistical Release H.15, Selected Interest Rates, Release Date 7/2/99, page 2 of 3.

5. The 4.80% risk free rate is average of the forecast of the 3 month Treasury Bill Rate for the years 1999-2000, from The Economic Outlook, An Update published 7/1/99 by the Congressional Budget Office, p. 5 of 24.

6. The 4.50% Short-term rate is the average of the projected 3-month Treasury Bill rate for the years 2001-2009 from The Economic Outlook, An Update published by the Congressional Budget Office, p. 6 of 24.

7. The 15.5% market return is from I/B/E/S obtained in the May 1999 Compact Disclosure.

8. The Value Line forecast for the market return is from the June 11, 1999 Value Line Index cover where the expected dividend Yield is 1.8% and the 4-year price appreciation potential is 60%.

Exhibit ________
Carl G. K. Weaver
Schedule 26

Bond Yield - Equity Risk Premium
Realized Return on Equity

	Stock Price & Dividend	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cascade	High	13.750	12.625	16.875	17.000	19.500	18.125	17.500	17.500	19.000	18.625
	Low	9.375	10.125	11.125	13.625	15.500	12.750	13.000	13.375	15.250	14.625
	Mid-range	11.563	11.375	14.000	15.313	17.500	15.438	15.250	15.438	17.125	16.625
	Dividend	0.850	0.870	0.900	0.930	0.940	0.960	0.960	0.960	0.960	0.960
	HPR		1.059	1.310	1.160	1.204	0.937	1.050	1.075	1.171	1.027
Conn. Energy	High	18.875	18.000	20.375	24.750	26.500	25.000	22.375	22.250	30.375	32.250
	Low	14.000	14.500	14.250	18.875	22.500	18.625	18.500	18.625	21.000	25.000
	Mid-range	16.438	16.250	17.313	21.813	24.500	21.813	20.438	20.438	25.688	28.625
	Dividend	1.200	1.230	1.240	1.260	1.280	1.290	1.300	1.310	1.320	1.330
	HPR		1.063	1.142	1.333	1.182	0.943	0.997	1.064	1.321	1.166
CTG Resources	High	19.000	18.625	21.500	28.375	32.375	31.750	25.250	25.500	26.500	26.750
	Low	15.125	16.000	16.250	20.000	26.250	22.125	21.250	21.750	20.750	21.875
	Mid-range	17.063	17.313	18.875	24.188	29.313	26.938	23.250	23.625	23.625	24.313
	Dividend	1.360	1.370	1.400	1.440	1.460	1.480	1.480	1.500	1.520	1.000
	HPR		1.095	1.171	1.358	1.272	0.969	0.918	1.081	1.064	1.071

Source: Standard & Poor's Stock Reports dated May 8, 1999.
Notes: The average annual price is the mid-range of the high and low price for the year.
HPR = (price1 + dividend1)/price0

Exhibit ________
Carl G. K. Weaver
Schedule 27

Bond Yield - Equity Risk Premium
Realized Return on Equity

	Stock Price & Dividend	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Energen	High	12.250	10.250	9.500	9.625	13.375	12.000	12.625	15.625	20.625	22.500
	Low	7.750	8.000	8.000	7.500	9.125	9.625	10.125	10.875	14.500	15.125
	Mid-range	10.000	9.125	8.750	8.563	11.250	10.813	11.375	13.250	17.563	18.813
	Dividend	0.430	0.450	0.480	0.510	0.530	0.550	0.560	0.580	0.600	0.940
	HPR		0.958	1.012	1.037	1.376	1.010	1.104	1.216	1.371	1.125
S. Jersey Ind.	High	22.875	20.625	20.375	23.125	27.500	24.000	23.500	24.625	30.500	30.750
	Low	17.625	16.375	17.375	19.125	21.875	16.625	17.875	20.125	21.000	22.000
	Mid-range	20.250	18.500	18.875	21.125	24.688	20.313	20.688	22.375	25.750	26.375
	Dividend	1.360	1.400	1.410	1.410	1.440	1.440	1.440	1.440	1.440	1.440
	HPR		0.983	1.096	1.194	1.237	0.881	1.089	1.151	1.215	1.080

Source: Standard & Poor's Stock Reports dated May 8, 1999..
Notes: The average annual price is the mid-range of the high and low price for the year.
HPR = (price1 + dividend1)/price0

Exhibit ________
Carl G. K. Weaver
Schedule 28

Bond Yield - Equity Risk Premium
Average One Year Holding Period Return

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cascade	1.059	1.310	1.160	1.204	0.937	1.050	1.075	1.171	1.027
Conn. Energy	1.063	1.142	1.333	1.182	0.943	0.997	1.064	1.321	1.166
CTG Resources	1.095	1.171	1.358	1.272	0.969	0.918	1.081	1.064	1.071
Energen	0.958	1.012	1.037	1.376	1.010	1.104	1.216	1.371	1.125
S. Jersey Ind.	0.983	1.096	1.194	1.237	0.881	1.089	1.151	1.215	1.080
Average	1.032	1.146	1.216	1.254	0.948	1.032	1.117	1.229	1.094

Source: Prior two schedules.

Exhibit ________
Carl G. K. Weaver
Schedule 29

Equity Yield
All Possible Combinations of Returns on Portfolio
Delta's Selected Comparable Companies

Investment Made at end of	1980	1991	1992	1993	1994	1995	1996	1997	1998
1989	3.2	8.7	12.9	15.9	11.3	9.9	10.2	11.7	11.4
1990		14.6	18.1	20.5	13.5	11.3	11.4	13.0	12.5
1991			21.6	23.5	13.1	10.5	10.8	12.7	12.2
1992				25.4	9.0	7.0	8.2	11.0	10.7
1993					-5.2	-1.1	3.0	7.6	8.0
1994						3.2	7.4	12.3	11.6
1995							11.7	17.2	14.5
1996								22.9	15.9
1997									9.4

Notes: Investment is assumed to be made at first of the year and return is realized at end of year.

Exhibit ________
Carl G. K. Weaver
Schedule 30

Bond Yield
All Possible Combinations of Returns on Portfolio
Composite Long-term Gov't Securities (over 10 Years)

Investment Made at end of	1990	1991	1992	1993	1994	1995	1996	1997	1998
1989	8.7	8.4	8.1	7.7	7.7	7.5	7.4	7.3	7.2
1990		8.2	7.8	7.4	7.4	7.3	7.2	7.1	7.0
1991			7.5	7.0	7.1	7.1	7.0	7.0	6.8
1992				6.5	6.9	6.9	6.9	6.9	6.7
1993					7.4	7.2	7.0	7.0	6.7
1994						6.9	6.9	6.8	6.5
1995							6.8	6.7	6.4
1996								6.7	6.2
1997									5.7

Notes: Investment is assumed to be made at first of the year and return is realized at end of year.
Returns are calculated as the G-mean of the annual bond yields.

Exhibit ________
Carl G. K. Weaver
Schedule 31

1990 - 1998 Risk Premiums

Investment Made at end of	Return at the end of Year Indicated								
	1990	1991	1992	1993	1994	1995	1996	1997	1998
1989	-5.6	0.3	4.7	8.2	3.7	2.4	2.7	4.4	4.3
1990		6.5	10.2	13.1	6.1	4.0	4.2	5.8	5.6
1991			14.1	16.5	6.0	3.4	3.7	5.7	5.4
1992				19.0	2.1	0.1	1.3	4.1	4.1
1993					-12.6	-8.3	-4.0	0.7	1.3
1994						-3.8	0.5	5.5	5.0
1995							4.9	10.4	8.1
1996								16.2	9.8
1997									3.7

Average Risk Premium 4.52

Note: The risk premium is the difference in the prior two schedlules.

Exhibit ________
Carl G. K. Weaver
Schedule 32

Delta Natural Gas Company, Inc.
Selected Comparable Companies
Risk Premium Analysis

Sources: Rf	Sources: Beta	Sources: Km	Risk Free Rate		Beta	Market Return		Delta Equity Risk Premium
Long-term Current	S&P	S&P 500	6.30%	(1)	0.31	15.5%	(7)	**2.85%**
Long-term Current	Value Line	S&P 500	6.30%		0.60	15.5%		**5.52%**
Long-term Current	S&P	Value Line	6.30%		0.31	12.5%	(8)	**1.92%**
Long-term Current	Value Line	Value Line	6.30%		0.60	12.5%		**3.72%**
Long-term Forecast	S&P	S&P 500	5.75%	(2)	0.31	15.5%		**3.02%**
Long-term Forecast	Value Line	S&P 500	5.75%		0.60	15.5%		**5.85%**
Long-term Forecast	S&P	Value Line	5.75%		0.31	12.5%		**2.09%**
Long-term Forecast	Value Line	Value Line	5.75%		0.60	12.5%		**4.05%**
Long-term Projected	S&P	S&P 500	5.40%	(3)	0.31	15.5%		**3.13%**
Long-term Projected	Value Line	S&P 500	5.40%		0.60	15.5%		**6.06%**
Long-term Projected	S&P	Value Line	5.40%		0.31	12.5%		**2.20%**
Long-term Projected	Value Line	Value Line	5.40%		0.60	12.5%		**4.26%**
Short-term Current	S&P	S&P 500	4.80%	(4)	0.31	15.5%		**3.32%**
Short-term Current	Value Line	S&P 500	4.80%		0.60	15.5%		**6.42%**
Short-term Current	S&P	Value Line	4.80%		0.31	12.5%		**2.39%**
Short-term Current	Value Line	Value Line	4.80%		0.60	12.5%		**4.62%**
Short-term Forecast	S&P	S&P 500	4.80%	(5)	0.31	15.5%		**3.32%**
Short-term Forecast	Value Line	S&P 500	4.80%		0.60	15.5%		**6.42%**
Short-term Forecast	S&P	Value Line	4.80%		0.31	12.5%		**2.39%**
Short-term Forecast	Value Line	Value Line	4.80%		0.60	12.5%		**4.62%**
Short-term Projected	S&P	S&P 500	4.50%	(6)	0.31	15.5%		**3.41%**
Short-term Projected	Value Line	S&P 500	4.50%		0.60	15.5%		**6.60%**
Short-term Projected	S&P	Value Line	4.50%		0.31	12.5%		**2.48%**
Short-term Projected	Value Line	Value Line	4.50%		0.60	12.5%		**4.80%**
Average of Delta Equity Risk Premium								**3.98%**
Standard Deviation of Equity Risk Premium								**1.52%**

Notes: Same as CAPM Sources

Exhibit ________
Carl G. K. Weaver
Schedule 33

Delta Natural Gas Company, Inc.
Cost of Long-term Debt
Yield to Maturity

General Debenture Bonds		Principal Amount (1)	Unamort. Debt Expense (2)	Carrying Value (3)	Maturity Date (4)	Settlement Date (5)	Price (6)	YTM	Wtd. YTM
Series	7.15%	25,000,000	1,202,205	23,797,795	3/31/18	3/31/98	95.191%	7.62%	3.50%
Series	8.30%	15,000,000	689,666	14,310,334	7/31/26	7/31/96	95.402%	8.74%	2.41%
Series	6.63%	13,170,000	753,063	12,416,937	10/31/23	10/31/93	94.282%	7.09%	1.72%
Note	0	1,192,494	0	1,192,494					
Other	0	40,000	0	40,000	1999				
		54,402,494		51,757,560					
Cost of Debt									7.63%

Source: Response to 7/2/99 data req. ques. 13 and Annual Report.

Exhibit ________
Carl G. K. Weaver
Schedule 34

Delta Natural Gas Company, Inc.
Weighted Average Cost of Capital
Fiscal Year 1998

	Proportion	Cost	Weighted Cost
Short-term Debt	2.20%	6.742	0.14833
Long-term Debt	63.20%	7.63	4.82216
Common Equity	34.60%	8.00 - 9.00	2.768 - 3.114
Total	100.00%		7.738 - 8.084

Sources: Short-term debt cost from data request, question 50.
Cost of Long-term debt from Schedule 27.