FootNOTE SUMMARY P. 1

FOOTNOTE	
1	Bruce Williams Direct 2:34 Capital Structure
2	Richard Wolfe Direct 2:35
3	" " " 3:35
4	" " " 3:48
5	" " " 3:50
6	" " " 3:53
7	" " " 3:55
8	" " " 3:56
9	" " " 3:56
10	" " " 6:124
11	See Table 2 at page 6 of DIC Testimony
12	Bruce Williams Capital Structure
	McDougal Rate Base SRM 1 p. 1of4, line 61
	See Attached.
13	Calculation of Tax Factor for Gross-up 1/(1-T)
14	FOMC 1/29/14 Press Release (See OCS_1.2D
15	FOMC 1/28/14 Annual Statement
16	FOMC 1/29/14 (See OCS_1.2D)
17	FOMC 3/18/14 (See OCS-1.2D)
18	Fed Reserve Historical SPOT Data
19	" " " " "
20	EEI 12/31/13 4th Quarter Report
21	9D
22	9D
23-24	Fitch Rating MEHC ATTACHED
25	MOODY'S Credit Opinion ATTACHED
26	MOODY'S ARTICLE ATTACHED

FOOTNOTE SUMMARY P. 2

Footnote	
27	Beta defined
28	SBBI IBBOTTSON ATTACHED
29	Morin chapter 5 p 163. ATTACHED
30	Reference OCS_1.7, 1.8, 1.9, 1.10
31	Bruce Williams Direct 2:34 Capital Structure.
32-34	Morin pp. 468-469
35	See OCS_1.11 Lines 12-19 Attached
36	Dr. Hadaway Washington Direct. Attached
37	Id.
38.	Dr. Hadaway Washington Rebuttal Attached
39	Id
40	Id
41	Dr. Hadaway Arkansas Direct Attached
42	Dr. Hadaway Arkansas Rebuttal Attached
43	Hadaway Ex. SCH-6 this case.

RMP 2014 GRC Filing Requirements

Confidential 746-700-22.D.16

The currently forecasted financings for the next three years.

Confidential Response to R746-700-22.D.16

At the present time, the Company anticipates long-term debt issuances as follows:

2014	$375 million
2015	$300 million
2016	$250 million

Confidential information is subject to R746-100-16 of the Commission Rules.

Rocky Mountain Power
Exhibit RMP___(SRM-1)
Docket No. 13-035-184
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Revenue Requirement Summary

January 2014

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending June 2015

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,884,107,463	76,252,101	1,960,359,564
3	Interdepartmental	-		
4	Special Sales	149,230,392		
5	Other Operating Revenues	70,387,117		
6	Total Operating Revenues	2,103,724,971		
7				
8	Operating Expenses:			
9	Steam Production	497,679,321		
10	Nuclear Production	-		
11	Hydro Production	17,563,929		
12	Other Power Supply	428,060,883		
13	Transmission	90,397,853		
14	Distribution	84,434,717		
15	Customer Accounting	34,650,973	148,303	34,799,276
16	Customer Service & Info	4,770,211		
17	Sales	-		
18	Administrative & General	60,710,458		
19				
20	Total O&M Expenses	1,218,268,346		
21				
22	Depreciation	262,390,668		
23	Amortization	22,885,961		
24	Taxes Other Than Income	63,068,116	-	63,068,116
25	Income Taxes - Federal	48,273,748	25,427,040	73,700,788
26	Income Taxes - State	10,751,193	3,455,112	14,206,306
27	Income Taxes - Def Net	63,481,630		
28	Investment Tax Credit Adj.	(4,098,178)		
29	Misc Revenue & Expense	682,017		
30				
31	Total Operating Expenses:	1,685,703,501	29,030,456	1,714,733,957
32				
33	Operating Rev For Return:	418,021,470	47,221,645	465,243,115
34				
35	Rate Base:			
36	Electric Plant In Service	10,912,081,614		
37	Plant Held for Future Use	18,651,670		
38	Misc Deferred Debits	170,287,197		
39	Elec Plant Acq Adj	15,449,004		
40	Nuclear Fuel	-		
41	Prepayments	13,702,489		
42	Fuel Stock	97,675,186		
43	Material & Supplies	86,820,549		
44	Working Capital	26,232,065		
45	Weatherization Loans	4,637,895		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	11,345,537,670	-	11,345,537,670
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,234,910,020)		
52	Accum Prov For Amort	(221,249,967)		
53	Accum Def Income Tax	(1,804,104,719)		
54	Unamortized ITC	(80,741)		
55	Customer Adv For Const	(9,924,958)		
56	Customer Service Deposits	(15,625,768)		
57	Misc Rate Base Deductions	(30,313,047)		
58				
59	Total Rate Base Deductions	(5,316,209,220)	-	(5,316,209,220)
60				
61	Total Rate Base:	6,029,328,450	-	6,029,328,450
62				
63	Return on Rate Base	6.933%		7.716%
64				
65	Return on Equity	8.482%		10.000%
66				
67	TAX CALCULATION:			
68	Operating Revenue	536,429,863	76,103,798	612,533,661
69	Other Deductions			
70	Interest (AFUDC)	(22,174,382)	-	(22,174,382)
71	Interest	154,052,563	-	154,052,563
72	Schedule "M" Additions	350,771,023	-	350,771,023
73	Schedule "M" Deductions	518,512,283	-	518,512,283
74	Income Before Tax	236,810,422	76,103,798	312,914,220
75				
76	State Income Taxes	10,751,193	3,455,112	14,206,306
77	Taxable Income	226,059,229	72,648,685	298,707,914
78				
79	Federal Income Taxes + Other	48,273,748	25,427,040	73,700,788

Rocky Mountain Power
UTAH
Normalized Results of Operations - ROLLED-IN
Twelve Months Ending June 2015

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,884,107,463	76,252,101	1,960,359,564
3	Interdepartmental	-		
4	Special Sales	149,230,392		
5	Other Operating Revenues	70,387,117		
6	Total Operating Revenues	2,103,724,971		
7				
8	Operating Expenses:			
9	Steam Production	497,679,321		
10	Nuclear Production	-		
11	Hydro Production	17,563,929		
12	Other Power Supply	428,060,883		
13	Transmission	90,397,853		
14	Distribution	84,434,717		
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16	Customer Service & Info	4,770,211		
17	Sales	-		
18	Administrative & General	60,710,458		
19				
20	Total O&M Expenses	1,218,268,346		
21				
22	Depreciation	262,390,668		
23	Amortization	22,885,961		
24	Taxes Other Than Income	63,068,116	-	63,068,116
25	Income Taxes - Federal	48,273,748	25,427,040	73,700,788
26	Income Taxes - State	10,751,193	3,455,112	14,206,306
27	Income Taxes - Def Net	63,481,630		
28	Investment Tax Credit Adj.	(4,098,178)		
29	Misc Revenue & Expense	682,017		
30				
31	Total Operating Expenses:	1,685,703,501	29,030,456	1,714,733,957
32				
33	Operating Rev For Return:	418,021,470	47,221,645	465,243,115
34				
35	Rate Base:			
36	Electric Plant In Service	10,912,081,614		
37	Plant Held for Future Use	18,651,670		
38	Misc Deferred Debits	170,287,197		
39	Elec Plant Acq Adj	15,449,004		
40	Nuclear Fuel	-		
41	Prepayments	13,702,489		
42	Fuel Stock	97,675,186		
43	Material & Supplies	86,820,549		
44	Working Capital	26,232,065		
45	Weatherization Loans	4,637,895		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	11,345,537,670	-	11,345,537,670
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,234,910,020)		
52	Accum Prov For Amort	(221,249,967)		
53	Accum Def Income Tax	(1,804,104,719)		
54	Unamortized ITC	(80,741)		
55	Customer Adv For Const	(9,924,958)		
56	Customer Service Deposits	(15,625,768)		
57	Misc Rate Base Deductions	(30,313,047)		
58				
59	Total Rate Base Deductions	(5,316,209,220)	-	(5,316,209,220)
60				
61	Total Rate Base:	6,029,328,450	-	6,029,328,450
62				
63	Return on Rate Base	6.933%		7.716%
64				
65	Return on Equity	8.482%		10.000%
66				
67	TAX CALCULATION:			
68	Operating Revenue	536,429,863	76,103,798	612,533,661
69	Other Deductions			
70	Interest (AFUDC)	(22,174,382)	-	(22,174,382)
71	Interest	154,052,563	-	154,052,563
72	Schedule "M" Additions	350,771,023	-	350,771,023
73	Schedule "M" Deductions	518,512,283	-	518,512,283
74	Income Before Tax	236,810,422	76,103,798	312,914,220
75				
76	State Income Taxes	10,751,193	3,455,112	14,206,306
77	Taxable Income	226,059,229	72,648,685	298,707,914
78				
79	Federal Income Taxes + Other	48,273,748	25,427,040	73,700,788

Rocky Mountain Power
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending June 2015

	Exhibit RMP___(SRM-3) Tab 2	Tab 2	Exhibit RMP___(SRM-3) Tab 3	Tab 4	Tab 5
	Total Company Actual Results June 2013	Utah Allocated Actual Results June 2013	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments
1 Operating Revenues:					
2 General Business Revenues	4,440,553,238	1,939,614,638	(55,507,175)	-	-
3 Interdepartmental	-	-	-	-	-
4 Special Sales	328,817,227	135,326,219	-	-	13,904,173
5 Other Operating Revenues	204,043,999	81,139,726	(11,655,644)	-	903,035
6 Total Operating Revenues	4,973,414,464	2,156,080,583	(67,162,819)	-	14,807,208
7					
8 Operating Expenses:					
9 Steam Production	1,088,441,448	458,734,056	-	13,648,689	25,630,640
10 Nuclear Production	-	-	-	-	-
11 Hydro Production	38,234,151	16,298,575	-	967,240	-
12 Other Power Supply	1,045,573,188	450,257,528	-	(1,104,463)	(20,823,201)
13 Transmission	201,709,294	85,930,306	(439,827)	249,064	4,687,199
14 Distribution	204,447,520	83,148,950	-	1,418,190	-
15 Customer Accounting	87,552,407	34,191,361	-	521,449	-
16 Customer Service & Info	109,336,777	50,948,786	-	(46,157,504)	-
17 Sales	-	-	-	-	-
18 Administrative & General	193,795,857	80,957,095	-	(20,094,658)	-
19					
20 Total O&M Expenses	2,969,090,641	1,260,466,657	(439,827)	(50,551,993)	9,494,637
21					
22 Depreciation	572,553,051	237,353,568	-	-	(73,090)
23 Amortization	53,648,631	22,373,319	-	(1,306,020)	-
24 Taxes Other Than Income	163,744,910	56,381,205	-	-	-
25 Income Taxes - Federal	12,635,438	21,573,999	(22,297,301)	19,424,419	1,796,514
26 Income Taxes - State	10,954,096	6,869,149	(3,029,833)	2,639,456	244,116
27 Income Taxes - Def Net	257,849,217	112,745,649	8,977	(2,394,665)	-
28 Investment Tax Credit Adj.	(1,831,667)	(1,502,644)	-	-	-
29 Misc Revenue & Expense	(435,263)	(266,711)	934	16,546	-
30					
31 Total Operating Expenses:	4,038,209,054	1,715,994,191	(25,757,050)	(32,172,258)	11,462,178
32					
33 Operating Rev For Return:	935,205,410	440,086,392	(41,405,770)	32,172,258	3,345,030
34					
35 Rate Base:					
36 Electric Plant In Service	23,605,170,060	10,033,832,359	-	-	(675,776)
37 Plant Held for Future Use	49,098,056	20,907,184	-	-	-
38 Misc Deferred Debits	311,085,926	39,292,022	-	(1,877,667)	-
39 Elec Plant Acq Adj	46,282,303	19,729,367	-	-	-
40 Nuclear Fuel	-	-	-	-	-
41 Prepayments	32,526,049	13,702,489	-	-	-
42 Fuel Stock	264,624,815	111,067,593	-	-	-
43 Material & Supplies	204,876,482	86,820,549	-	-	189,159
44 Working Capital	59,104,798	26,494,229	(422,534)	(467,156)	-
45 Weatherization Loans	(6,814,340)	4,640,730	-	-	-
46 Misc Rate Base	-	-	-	-	-
47					
48 Total Electric Plant	24,565,954,148	10,356,486,522	(422,534)	(2,344,823)	(486,618)
49					
50 Rate Base Deductions:					
51 Accum Prov For Deprec	(7,379,345,761)	(2,947,460,107)	-	-	825,058
52 Accum Prov For Amort	(502,655,381)	(212,964,427)	-	-	-
53 Accum Def Income Tax	(3,634,945,474)	(1,553,478,568)	9,058	2,875,518	-
54 Unamortized ITC	(2,606,988)	(108,793)	-	-	-
55 Customer Adv For Const	(20,902,843)	(8,237,438)	-	-	-
56 Customer Service Deposits	-	-	-	-	-
57 Misc Rate Base Deductions	(105,083,207)	(30,517,434)	(23,868)	-	-
58					
59 Total Rate Base Deductions	(11,645,539,654)	(4,752,766,766)	(14,810)	2,875,518	825,058
60					
61 Total Rate Base:	12,920,414,494	5,603,719,756	(437,344)	530,694	338,441
62					
63 Return on Rate Base	7.238%	7.853%	-0.738%	0.573%	0.059%
64					
65 Return on Equity	9.073%	10.266%	-1.431%	1.111%	0.115%
66					
67 TAX CALCULATION:					
68 Operating Revenue		579,772,545	(66,723,926)	51,841,468	5,385,660
69 Other Deductions					
70 Interest (AFUDC)		(25,234,835)	-	-	-
71 Interest		143,178,033	(11,174)	13,560	8,647
72 Schedule "M" Additions		343,149,373	-	(145,597)	-
73 Schedule "M" Deductions		653,675,878	23,655	(6,455,483)	-
74 Income Before Tax		151,302,842	(66,736,407)	58,137,794	5,377,013
75					
76 State Income Taxes		6,869,149	(3,029,833)	2,639,456	244,116
77 Taxable Income		144,433,693	(63,706,574)	55,498,339	5,132,897
78					
79 Federal Income Taxes + Other		21,573,999	(22,297,301)	19,424,419	1,796,514
APPROXIMATE REVISED PROTOCOL PRICE CHANGE		(12,408,967)	66,809,428	(51,887,799)	(5,359,285)

Rocky Mountain Power
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending June 2015

	Exhibit RMP___(SRM-3) Tab 6 Depreciation & Amortization Adjustments	Exhibit RMP___(SRM-3) Tab 7 Tax Adjustments	Exhibit RMP___(SRM-3) Tab 8 Rate Base Adjustments	Exhibit RMP___(SRM-3) Tab 2 Utah Normalized Results June 2015
1 Operating Revenues:				
2 General Business Revenues	-	-	-	1,884,107,463
3 Interdepartmental	-	-	-	-
4 Special Sales	-	-	-	149,230,392
5 Other Operating Revenues	-	-	-	70,387,117
6 Total Operating Revenues	-	-	-	2,103,724,971
7				
8 Operating Expenses:				
9 Steam Production	(334,064)	-	-	497,679,321
10 Nuclear Production	-	-	-	-
11 Hydro Production	(70,332)	-	368,446	17,563,929
12 Other Power Supply	(55,669)	-	(213,312)	428,060,883
13 Transmission	(28,887)	-	-	90,397,853
14 Distribution	(132,422)	-	-	84,434,717
15 Customer Accounting	(61,837)	-	-	34,650,973
16 Customer Service & Info	(10,249)	-	(10,821)	4,770,211
17 Sales	-	-	-	-
18 Administrative & General	(121,683)	-	(30,297)	60,710,458
19				
20 Total O&M Expenses	(815,144)	-	114,016	1,218,268,346
21				
22 Depreciation	37,926,625	-	(12,816,434)	262,390,668
23 Amortization	(735,073)	-	2,553,736	22,885,961
24 Taxes Other Than Income	-	6,686,910	-	63,068,116
25 Income Taxes - Federal	(9,461,231)	45,646,783	(8,409,435)	48,273,748
26 Income Taxes - State	(1,285,624)	6,456,631	(1,142,703)	10,751,193
27 Income Taxes - Def Net	-	(50,844,211)	3,965,879	63,481,630
28 Investment Tax Credit Adj.	-	(2,595,534)	-	(4,098,178)
29 Misc Revenue & Expense	-	-	931,249	682,017
30				
31 Total Operating Expenses:	25,629,552	5,350,580	(14,803,692)	1,685,703,501
32				
33 Operating Rev For Return:	(25,629,552)	(5,350,580)	14,803,692	418,021,470
34				
35 Rate Base:				
36 Electric Plant In Service	-	-	878,925,031	10,912,081,614
37 Plant Held for Future Use	-	-	(2,255,514)	18,651,670
38 Misc Deferred Debits	-	-	132,872,843	170,287,197
39 Elec Plant Acq Adj	-	-	(4,280,363)	15,449,004
40 Nuclear Fuel	-	-	-	-
41 Prepayments	-	-	-	13,702,489
42 Fuel Stock	-	-	(13,392,407)	97,675,186
43 Material & Supplies	-	-	-	86,820,549
44 Working Capital	(189,597)	964,060	(336,096)	26,232,065
45 Weatherization Loans	-	-	(2,835)	4,637,895
46 Misc Rate Base	-	-	-	-
47				
48 Total Electric Plant:	(189,597)	964,060	991,530,659	11,345,537,670
49				
50 Rate Base Deductions:				
51 Accum Prov For Deprec	(302,122,328)	-	13,847,357	(3,234,910,020)
52 Accum Prov For Amort	(13,090,269)	-	4,804,729	(221,249,967)
53 Accum Def Income Tax	-	(197,313,833)	(56,196,894)	(1,804,104,719)
54 Unamortized ITC	-	28,051	-	(80,741)
55 Customer Adv For Const	-	-	(1,687,520)	(9,924,958)
56 Customer Service Deposits	-	-	(15,625,768)	(15,625,768)
57 Misc Rate Base Deductions	-	47,854	180,401	(30,313,047)
58				
59 Total Rate Base Deductions	(315,212,598)	(197,237,928)	(54,677,694)	(5,316,209,220)
60				
61 Total Rate Base:	(315,402,195)	(196,273,868)	936,852,965	6,029,328,450
62				
63 Return on Rate Base	-0.023%	0.193%	-0.985%	6.933%
64				
65 Return on Equity	-0.044%	0.373%	-1.908%	8.482%
66				
67 TAX CALCULATION:				
68 Operating Revenue	(36,376,408)	(6,686,910)	9,217,434	536,429,863
69 Other Deductions				
70 Interest (AFUDC)	-	3,060,454	-	(22,174,382)
71 Interest	(8,058,695)	(5,014,902)	23,937,094	154,052,563
72 Schedule "M" Additions	-	18,223,651	(10,456,404)	350,771,023
73 Schedule "M" Deductions	-	(128,725,362)	(6,405)	518,512,283
74 Income Before Tax	(28,317,713)	142,216,551	(25,169,659)	236,810,422
75				
76 State Income Taxes	(1,285,624)	6,456,631	(1,142,703)	10,751,193
77 Taxable Income	(27,032,089)	135,759,920	(24,026,957)	226,059,229
78				
79 Federal Income Taxes + Other	(9,461,231)	45,646,783	(8,409,435)	48,273,748
APPROXIMATE REVISED PROTOCOL PRICE CHANGE	2,086,389	(15,815,973)	92,828,307	76,252,101

FN-15

Statement on Longer-Run Goals and Monetary Policy Strategy

As amended effective January 28, 2014

The Federal Open Market Committee (FOMC) is firmly committed to fulfilling its statutory mandate from the Congress of promoting maximum employment, stable prices, and moderate long-term interest rates. The Committee seeks to explain its monetary policy decisions to the public as clearly as possible. Such clarity facilitates well-informed decisionmaking by households and businesses, reduces economic and financial uncertainty, increases the effectiveness of monetary policy, and enhances transparency and accountability, which are essential in a democratic society.

Inflation, employment, and long-term interest rates fluctuate over time in response to economic and financial disturbances. Moreover, monetary policy actions tend to influence economic activity and prices with a lag. Therefore, the Committee's policy decisions reflect its longer-run goals, its medium-term outlook, and its assessments of the balance of risks, including risks to the financial system that could impede the attainment of the Committee's goals.

The inflation rate over the longer run is primarily determined by monetary policy, and hence the Committee has the ability to specify a longer-run goal for inflation. The Committee reaffirms its judgment that inflation at the rate of 2 percent, as measured by the annual change in the price index for personal consumption expenditures, is most consistent over the longer run with the Federal Reserve's statutory mandate. Communicating this inflation goal clearly to the public helps keep longer-term inflation expectations firmly anchored, thereby fostering price stability and moderate long-term interest rates and enhancing the Committee's ability to promote maximum employment in the face of significant economic disturbances.

The maximum level of employment is largely determined by nonmonetary factors that affect the structure and dynamics of the labor market. These factors may change over time and may not be directly measurable. Consequently, it would not be appropriate to specify a fixed goal for employment; rather, the Committee's policy decisions must be informed by assessments of the maximum level of employment, recognizing that such assessments are necessarily uncertain and subject to revision. The Committee considers a wide range of indicators in making these assessments. Information about Committee participants' estimates of the longer-run normal rates of output growth and unemployment is published four times per year in the FOMC's Summary of Economic Projections. For example, in the most recent projections, FOMC participants' estimates of the longer-run normal rate of unemployment had a central tendency of 5.2 percent to 5.8 percent.

In setting monetary policy, the Committee seeks to mitigate deviations of inflation from its longer-run goal and deviations of employment from the Committee's assessments of its maximum level. These objectives are generally complementary. However, under circumstances in which the Committee judges that the objectives are not complementary, it follows a balanced approach in promoting them, taking into account the magnitude of the deviations and the potentially different time horizons over which employment and inflation are projected to return to levels judged consistent with its mandate.

The Committee intends to reaffirm these principles and to make adjustments as appropriate at its annual organizational meeting each January.

FN-18
FN-19

DDP Print

Selected Interest Rates (Weekly) - H.15

Current Release · Release Dates · Daily Update · Historical Data · About · Announcements · Technical Q&As

Current Release (48 KB PDF)

Release Date: March 31, 2014

The weekly release is posted on Monday. Daily updates of the weekly release are posted Tuesday through Friday on this site. If Monday is a holiday, the weekly release will be posted on Tuesday after the holiday and the daily update will not be posted on that Tuesday.

March 31, 2014
H.15 Selected Interest Rates
Yields in percent per annum

Instruments	2014 Mar 24	2014 Mar 25	2014 Mar 26	2014 Mar 27	2014 Mar 28	Week Ending Mar 28	Week Ending Mar 21	2014 Feb
Federal funds (effective) 1 2 3	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.07
Commercial Paper 3 4 5 6								
Nonfinancial								
1-month	0.06	n.a.	0.06	0.06	0.06	0.06	0.06	0.06
2-month	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08
3-month	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Financial								
1-month	0.07	0.06	0.07	0.06	0.06	0.06	0.07	0.07
2-month	0.10	0.09	0.09	0.11	0.10	0.10	0.11	0.11
3-month	0.12	0.11	0.10	0.13	0.13	0.12	0.12	0.13
Eurodollar deposits (London) 3 7								
1-month	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
3-month	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
6-month	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
Bank prime loan 2 3 8	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Discount window primary credit 2 9	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
U.S. government securities								
Treasury bills (secondary market) 3 4								
4-week	0.05	0.05	0.05	0.02	0.03	0.04	0.06	0.05
3-month	0.06	0.05	0.05	0.04	0.04	0.05	0.06	0.05
6-month	0.08	0.08	0.07	0.06	0.06	0.07	0.08	0.08
1-year	0.13	0.12	0.11	0.11	0.12	0.12	0.13	0.11
Treasury constant maturities								
Nominal 10								
1-month	0.05	0.05	0.05	0.02	0.03	0.04	0.06	0.05
3-month	0.06	0.05	0.05	0.04	0.04	0.05	0.06	0.05

6-month	0.08	0.08	0.07	0.06	0.06	0.07	0.08	0.08
1-year	0.14	0.13	0.12	0.12	0.13	0.13	0.14	0.12
2-year	0.47	0.47	0.45	0.45	0.45	0.46	0.42	0.33
3-year	0.93	0.92	0.89	0.90	0.93	0.91	0.85	0.69
5-year	1.76	1.76	1.70	1.70	1.74	1.73	1.67	1.52
7-year	2.31	2.32	2.27	2.26	2.31	2.29	2.25	2.15
10-year	2.74	2.75	2.71	2.69	2.73	2.72	2.74	2.71
20-year	3.31	3.32	3.29	3.25	3.29	3.29	3.36	3.38
30-year	3.57	3.59	3.55	3.52	3.55	3.56	3.64	3.66
Inflation indexed 11								
5-year	-0.03	0.06	-0.05	-0.03	0.02	-0.01	-0.10	-0.26
7-year	0.41	0.51	0.40	0.41	0.46	0.44	0.40	0.30
10-year	0.59	0.61	0.57	0.56	0.60	0.59	0.58	0.55
20-year	1.04	1.05	1.01	1.00	1.03	1.03	1.08	1.12
30-year	1.30	1.30	1.27	1.24	1.28	1.28	1.35	1.40
Inflation-indexed long-term average 12	1.02	1.03	1.00	0.97	1.02	1.01	1.06	1.04
Interest rate swaps 13								
1-year	0.29	0.28	0.28	0.28	0.28	0.28	0.28	0.27
2-year	0.58	0.57	0.56	0.57	0.57	0.57	0.52	0.45
3-year	1.03	1.01	1.00	1.02	1.03	1.02	0.92	0.81
4-year	1.47	1.44	1.43	1.44	1.45	1.44	1.34	1.22
5-year	1.83	1.80	1.80	1.80	1.81	1.81	1.72	1.62
7-year	2.38	2.36	2.35	2.34	2.35	2.35	2.30	2.24
10-year	2.87	2.85	2.84	2.82	2.83	2.84	2.83	2.81
30-year	3.57	3.57	3.55	3.51	3.52	3.54	3.61	3.65
Corporate bonds								
Moody's seasoned								
Aaa 14	4.35	4.36	4.33	4.29	4.31	4.33	4.42	4.45
Baa	5.03	5.03	4.99	4.95	4.98	5.00	5.11	5.10
State & local bonds 15				4.43		4.43	4.51	4.44
Conventional mortgages 16				4.40		4.40	4.32	4.30

n.a. Not available.

Footnotes

1. The daily effective federal funds rate is a weighted average of rates on brokered trades.

2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.

3. Annualized using a 360-day year or bank interest.

4. On a discount basis.

5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp/).

6. Financial paper that is insured by the FDIC's Temporary Liquidity Guarantee Program is not excluded from relevant indexes, nor is any financial or nonfinancial commercial paper that may be directly or indirectly affected by one or more of the Federal Reserve's liquidity facilities. Thus the rates published after September 19, 2008, likely reflect the direct or indirect effects of the new temporary programs and, accordingly, likely are not comparable for some purposes to rates published prior to that period.

7. Source: Bloomberg and CTRB ICAP Fixed Income & Money Market Products.

8. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.

9. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January

8, 2003. For further information, see www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at www.federalreserve.gov/releases/h15/data.htm.

10. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. The 30-year Treasury constant maturity series was discontinued on February 18, 2002, and reintroduced on February 9, 2006. From February 18, 2002, to February 9, 2006, the U.S. Treasury published a factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate. The historical adjustment factor can be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/. Source: U.S. Treasury.

11. Yields on Treasury inflation protected securities (TIPS) adjusted to constant maturities. Source: U.S. Treasury. Additional information on both nominal and inflation-indexed yields may be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/.

12. Based on the unweighted average bid yields for all TIPS with remaining terms to maturity of more than 10 years.

13. International Swaps and Derivatives Association (ISDA®) mid-market par swap rates. Rates are for a Fixed Rate Payer in return for receiving three month LIBOR, and are based on rates collected at 11:00 a.m. Eastern time by Thomson Reuters and published on Thomson Reuters Page ISDAFIX®1. ISDAFIX is a registered service mark of ISDA®. Source: Thomson Reuters.

14. Moody's Aaa rates through December 6, 2001, are averages of Aaa utility and Aaa industrial bond rates. As of December 7, 2001, these rates are averages of Aaa industrial bonds only.

15. Bond Buyer Index, general obligation, 20 years to maturity, mixed quality; Thursday quotations.

16. Contract interest rates on commitments for 30-year fixed-rate first mortgages. Source: Primary Mortgage Market Survey® data provided by Freddie Mac.

Note: Weekly and monthly figures on this release, as well as annual figures available on the Board's historical H.15 web site (see below), are averages of business days unless otherwise noted.

Current and historical H.15 data are available on the Federal Reserve Board's web site (www.federalreserve.gov/). For information about individual copies or subscriptions, contact Publications Services at the Federal Reserve Board (phone 202-452-3244, fax 202-728-5886).

Description of the Treasury Nominal and Inflation-Indexed Constant Maturity Series

Yields on Treasury nominal securities at "constant maturity" are interpolated by the U.S. Treasury from the daily yield curve for non-inflation-indexed Treasury securities. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 1, 3, and 6 months and 1, 2, 3, 5, 7, 10, 20, and 30 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. Similarly, yields on inflation-indexed securities at "constant maturity" are interpolated from the daily yield curve for Treasury inflation protected securities in the over-the-counter market. The inflation-indexed constant maturity yields are read from this yield curve at fixed maturities, currently 5, 7, 10, 20, and 30 years.

Last update: March 31, 2014

EN 20-28

EEI

Rate Case Summary

Q4 2013
FINANCIAL UPDATE

QUARTERLY REPORT
OF THE U.S. SHAREHOLDER-OWNED
ELECTRIC UTILITY INDUSTRY

About EEI

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With more than $85 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable, and sustainable electricity powers the economy and enhances the lives of all Americans. EEI has 70 international electric companies as Affiliate Members, and 250 industry suppliers and related organizations as Associate Members. Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

About EEI's Quarterly Financial Updates

EEI's quarterly financial updates present industry trend analyses and financial data covering 55 U.S. shareholder-owned electric utility companies. These 55 companies include 49 electric utility holding companies whose stocks are traded on major U.S. stock exchanges and six electric utilities who are subsidiaries of non-utility or foreign companies. Financial updates are published for the following topics:

Dividends	Rate Case Summary
Stock Performance	SEC Financial Statements (Holding Companies)
Credit Ratings	FERC Financial Statements (Regulated Utilities)
Construction	Fuel

For EEI Member Companies

The EEI Finance and Accounting Division is developing current year and historical data sets that cover a wide range of industry financial and operating metrics. We look forward to serving as a resource for member companies who wish to produce customized industry financial data and trend analyses for use in:

- Investor relations studies and presentations
- Internal company presentations
- Performance benchmarking
- Peer group analyses
- Annual and quarterly reports to shareholders

We Welcome Your Feedback

EEI is interested in ensuring that our financial publications and industry data sets best address the needs of member companies and the financial community. We welcome your comments, suggestions and inquiries.

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Future EEI Finance Meetings

EEI International Utility Conference
March 9-12, 2014
London Hilton on Park Lane
London, United Kingdom

For more information about EEI Finance Meetings, please contact Debra Henry, (202) 508-5496, dhenry@eei.org

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The 55 U.S. Shareholder-Owned Electric Utilities

The companies listed below all serve a regulated distribution territory. Other utilities, such as transmission provider ITC Holdings, are not shown below because they do not serve a regulated distribution territory. However, their financial information is included in relevant EEI data sets, such as transmission-related construction spending.

ALLETE, Inc. (ALE)
Alliant Energy Corporation (LNT)
Ameren Corporation (AEE)
American Electric Power Company, Inc. (AEP)
Avista Corporation (AVA)
Black Hills Corporation (BKH)
CenterPoint Energy, Inc. (CNP)
Cleco Corporation (CNL)
CMS Energy Corporation (CMS)
Consolidated Edison, Inc. (ED)
Dominion Resources, Inc. (D)
DPL, Inc.
DTE Energy Company (DTE)
Duke Energy Corporation (DUK)
Edison International (EIX)
El Paso Electric Company (EE)
Empire District Electric Company (EDE)
Energy Future Holdings Corp. (formerly TXU Corp.)
Entergy Corporation (ETR)
Exelon Corporation (EXC)
FirstEnergy Corp. (FE)
Great Plains Energy Incorporated (GXP)
Hawaiian Electric Industries, Inc. (HE)
Iberdrola USA
IDACORP, Inc. (IDA)
Integrys Energy Group, Inc. (TEG)
IPALCO Enterprises, Inc.
MDU Resources Group, Inc. (MDU)
MGE Energy, Inc. (MGEE)
MidAmerican Energy Holdings Company
NextEra Energy, Inc. (NEE)
NiSource Inc. (NI)
Northeast Utilities (NU)
NorthWestern Corporation (NWE)
OGE Energy Corp. (OGE)
Otter Tail Corporation (OTTR)
Pepco Holdings, Inc. (POM)
PG&E Corporation (PCG)
Pinnacle West Capital Corporation (PNW)
PNM Resources, Inc. (PNM)
Portland General Electric Company (POR)
PPL Corporation (PPL)
Public Service Enterprise Group Inc. (PEG)
Puget Energy, Inc.
SCANA Corporation (SCG)
Sempra Energy (SRE)
Southern Company (SO)
TECO Energy, Inc. (TE)
UIL Holdings Corporation (UIL)
Unitil Corporation (UTL)
UNS Energy Corporation (UNS)
Vectren Corporation (VVC)
Westar Energy, Inc. (WR)
Wisconsin Energy Corporation (WEC)
Xcel Energy, Inc. (XEL)

Companies Listed by Category
(as of 12/31/12)

Please refer to the Quarterly Financial Updates webpage for previous years' lists.

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Never-the-less, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80%+ of total assets are regulated
Mostly Regulated	50% to 80% of total assets are regulated
Diversified	Less than 50% of total assets are regulated

Categorization of the 49 publicly traded utility holding companies is based on year-end business segmentation data presented in 10Ks, supplemented by discussions with company IR departments. Categorization of the six non-publicly traded companies (*shown in italics*) is based on estimates derived from FERC Form 1 data and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (36 of 55)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
Cleco Corporation
CMS Energy Corporation
Consolidated Edison, Inc.
DPL, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Empire District Electric Company
Entergy Corporation
Great Plains Energy Incorporated
Iberdrola USA
IDACORP, Inc.
Integrys Energy Group
IPALCO Enterprises, Inc.
Northeast Utilities
NorthWestern Energy
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
Puget Energy, Inc.
Southern Company
TECO Energy, Inc.
UIL Holdings Corporation
Unitil Corporation
UNS Energy Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy, Inc.

Mostly Regulated (17 of 55)

CenterPoint Energy, Inc.
Dominion Resources, Inc.
Exelon Corporation
First Energy Corp.
Hawaiian Electric Industries, Inc.
MGE Energy, Inc.
MidAmerican Energy Holdings
NextEra Energy, Inc.
NiSource Inc.
OGE Energy Corp.
Otter Tail Corporation
Pepco Holdings, Inc.
PPL Corporation
Public Service Enterprise Group, Inc.
SCANA Corporation
Sempra Energy
Vectren Corporation

Diversified (2 of 55)

Energy Future Holdings
MDU Resources Group, Inc.

Note: Based on assets at 12/31/12

Q4 2013

Rate Case Summary

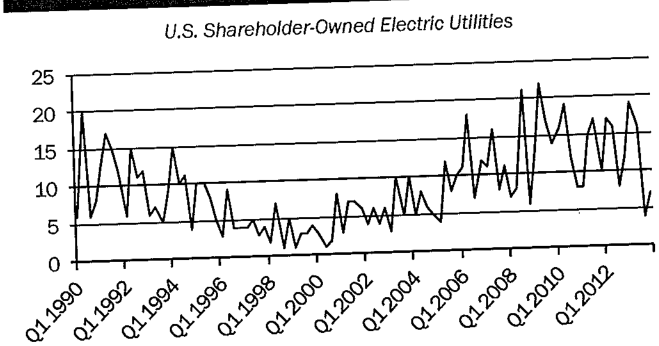
HIGHLIGHTS

- Shareholder-owned electric utilities filed seven rate cases in Q4 and 46 in 2013, for the lowest number of annual filings since 2009. However, 24 cases were decided in Q4 and utilities rarely file a new case with one still in progress. We expect the number of filings to remain high, reflecting the industry's ongoing elevated capital investment.
- The average allowed ROE in Q4, at 9.90%, was near the bottom of a long trend of declining allowed ROEs caused by falling interest rates and, in recent years, commissions' concerns about keeping rates low in economically challenging times.
- Capital investment, recovery of O&M, trackers and riders, storm cost recovery and weak power demand were primary reasons for Q4 and full-year 2013 case filings.
- The average regulatory lag for 2013 was 8.42 months, lower than in recent years but not likely indicative of commission efforts to reduce lag.

COMMENTARY

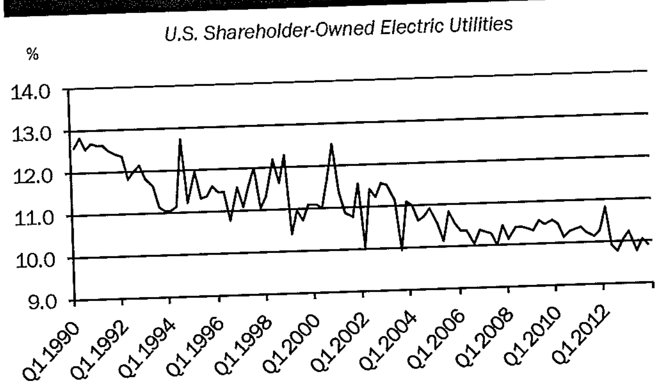
Shareholder-owned electric utilities filed seven new rate cases in the fourth quarter of 2013 and a total of 46 for the full year, the lowest number of annual filings since 2009. When combined with the four cases filed in the third quarter, the slow pace of filings in the year's second half might suggest a reversal in the trend of escalating rate case activity since the year 2000. However, 24 cases were decided in Q4 and utilities rarely file a case while another is still in progress. We expect the number of filings to remain high, reflecting the industry's ongoing construction cycle driven by the need to replace and upgrade infrastructure and reduce the environmental impact of power generation.

I. Number of Rate Cases Filed (Quarterly)



Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

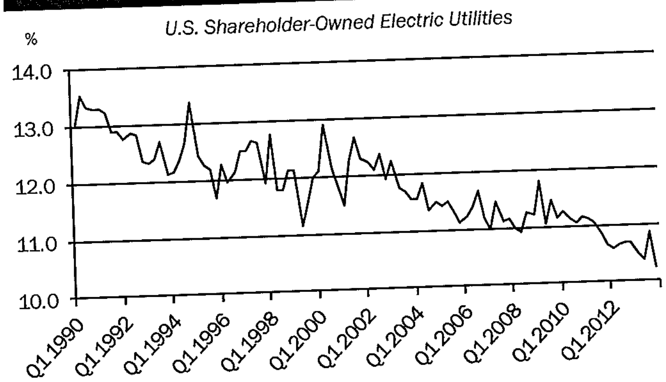
II. Average Awarded ROE (Quarterly)



Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

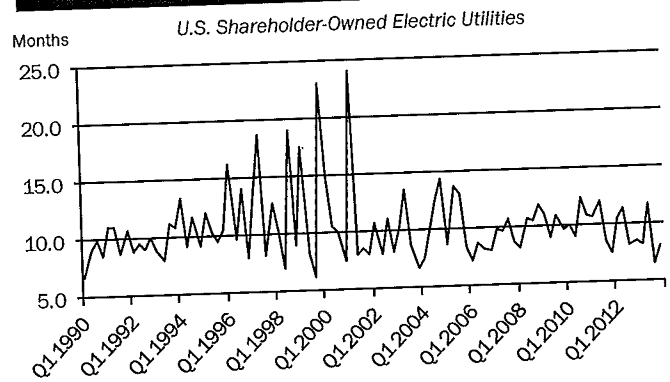
The primary reason for the fourth quarter's filings was capital investment, the most frequently cited driver of rate cases in recent years. Another prevalent factor in Q4 was storm recovery. Capital investment was also the major driver of filings in full-year 2013, as it has been each year since the

III. Average Requested ROE (Quarterly)



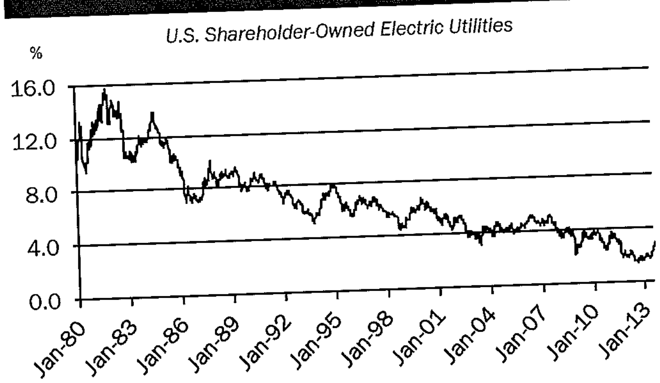
Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

IV. Average Regulatory Lag (Quarterly)



Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

V. 10-Year Treasury Yield (1/1980 – 12/2013)



Source: U.S. Federal Reserve

initiation of this report series. Utilities' efforts to implement adjustment mechanisms, such as trackers and riders, was the second major driver of filings in 2013, edging out recovery of rising operation and maintenance (O&M) expenses. Trackers and O&M recovery have also been regular causes of filings in recent years. Finally, storm cost recovery was cited in many filings in 2013, as were efforts to recover for revenue shortfalls caused by low demand growth in the industry.

The average allowed ROE in Q4, at 9.90%, was the third lowest quarterly total in recent decades and near the bottom of a long trend of declining allowed ROEs caused by falling interest rates and, in recent years, commissions' concerns about rate increases in economically challenging times.

The average allowed ROE for 2013 was 10.02%, the lowest in our decades of data. The average allowed ROE for 2012 was 10.15%. The last four years have each set successive record lows.

The average requested ROE in Q4 was also a record low, at 10.24%, and for similar reasons as the decline in allowed ROE. The average requested ROE for 2013 was 10.46%, a record low and below 2012's 10.72%, and the fourth in a series of consecutive annual record lows.

Average regulatory lag in Q4, at 8.14 months, was a bit lower than the average regulatory lag that has held for the past decade (at around ten months). Based on a review of rate case decisions, the slightly lower number does not seem to indicate attempts by commissions to decrease lag during a time of heavy industry investment. Around the turn of the century, during industry restructuring, regulatory lag was more volatile and generally higher. The average regulatory lag for 2013 was 8.42 months, lower than in recent years but not likely suggestive of commission efforts to reduce lag.

Filed Cases in Q4

Storm and Other Reliability Issues

In addition to capital investment (the usual driver of rate case filings), spending on storm preparedness and other reliability efforts was a major driver of filings in Q4. Rockland Electric in New Jersey filed to recover costs from three storms: $11 million of the company's requested $19.3 million increase was for Hurricane Irene, a 2011 snow storm, and Superstorm Sandy. The $11 million includes $2.2 million for increased storm reserves and $1 million for storm hardening. The company also filed for a surcharge for recovery of future storm-hardening projects.

The primary driver of Northern States Power's Q4 filing in Minnesota was increased capital investment, in part to provide customers with increased reliability by lengthening the life of the company's nuclear plants and strengthening the grid. Similarly, Potomac Electric Power in Maryland hopes to get recovery for $240 million spent on infrastructure enhancements, which have allowed the company to achieve reliability metrics required by the commission.

Northern States Power – Minnesota

NSP proposed a "rate modernization plan" that would accelerate from eight years to three years the amortization of transmission, distribution and generation plant depreciation reserve surplus and use funds from a settlement with the Department of Energy to mitigate the impact on ratepayers.

VI. Rate Case Data: From Tables I-V

U.S. Shareholder-Owned Electric Utilities

Quarter	Number of Rate Cases Filed	Average Awarded ROE	Average Requested ROE	Average 10-Year Treasury Yield	Average Regulatory Lag
Q4 1988	1	NA	14.30	8.96	NA
Q1 1989	4	NA	15.26	9.21	NA
Q2 1989	4	NA	13.30	8.77	NA
Q3 1989	14	NA	13.65	8.11	NA
Q4 1989	13	NA	13.47	7.91	NA
Q1 1990	6	12.62	13.00	8.42	6.71
Q2 1990	20	12.85	13.51	8.68	9.07
Q3 1990	6	12.54	13.34	8.70	9.90
Q4 1990	8	12.68	13.31	8.40	8.61
Q1 1991	13	12.66	13.29	8.02	11.00
Q2 1991	17	12.67	13.23	8.13	11.00
Q3 1991	15	12.49	12.89	7.94	8.70
Q4 1991	12	12.42	12.90	7.35	10.70
Q1 1992	6	12.38	12.77	7.30	8.90
Q2 1992	15	11.83	12.86	7.38	9.61
Q3 1992	11	12.03	12.81	6.62	9.00
Q4 1992	12	12.14	12.36	6.74	10.10
Q1 1993	6	11.84	12.33	6.28	8.87
Q2 1993	7	11.64	12.39	5.99	8.10
Q3 1993	5	11.15	12.70	5.62	11.20
Q4 1993	9	11.04	12.12	5.61	10.90
Q1 1994	15	11.07	12.15	6.07	13.40
Q2 1994	10	11.13	12.37	7.08	9.28
Q3 1994	11	12.75	12.66	7.33	11.80
Q4 1994	4	11.24	13.36	7.84	9.26
Q1 1995	10	11.96	12.44	7.48	12.00
Q2 1995	10	11.32	12.26	6.62	10.40
Q3 1995	8	11.37	12.19	6.32	9.50
Q4 1995	5	11.58	11.69	5.89	10.60
Q1 1996	3	11.46	12.25	5.91	16.30
Q2 1996	9	11.46	11.96	6.72	9.80
Q3 1996	4	10.76	12.13	6.78	14.00
Q4 1996	4	11.56	12.48	6.34	8.12
Q1 1997	4	11.08	12.50	6.56	13.80
Q2 1997	5	11.62	12.66	6.70	18.70
Q3 1997	3	12.00	12.63	6.24	8.33
Q4 1997	4	11.06	11.93	5.91	12.70
Q1 1998	2	11.31	12.75	5.59	10.20
Q2 1998	7	12.20	11.78	5.60	7.00
Q3 1998	1	11.65	NA	5.20	19.00
Q4 1998	5	12.30	12.11	4.67	9.11
Q1 1999	1	10.40	NA	4.98	17.60
Q2 1999	3	10.94	11.17	5.54	8.33
Q3 1999	3	10.75	11.57	5.88	6.33
Q4 1999	4	11.10	12.00	6.14	23.00
Q1 2000	3	11.08	12.10	6.48	15.10
Q2 2000	1	11.00	12.90	6.18	10.50
Q3 2000	2	11.68	12.13	5.89	10.00
Q4 2000	8	12.50	11.81	5.57	7.50
Q1 2001	3	11.38	11.50	5.05	24.00
Q2 2001	7	10.88	12.24	5.27	8.00
Q3 2001	7	10.78	12.64	4.98	8.62
Q4 2001	6	11.57	12.29	4.77	8.00
Q1 2002	4	10.05	12.22	5.08	10.80
Q2 2002	6	11.41	12.08	5.10	8.16
Q3 2002	4	11.25	12.36	4.26	11.00
Q4 2002	6	11.57	11.92	4.01	8.25

VI. Rate Case Data: From Tables I-V (cont.)

U.S. Shareholder-Owned Electric Utilities

Quarter	Number of Rate Cases Filed	Average Awarded ROE	Average Requested ROE	Average 10-Year Treasury Yield	Average Regulatory Lag
Q1 2003	3	11.49	12.24	3.92	10.20
Q2 2003	10	11.16	11.76	3.62	13.60
Q3 2003	5	9.95	11.69	4.23	8.80
Q4 2003	10	11.09	11.57	4.29	6.83
Q1 2004	5	11.00	11.54	4.02	7.66
Q2 2004	8	10.64	11.81	4.60	10.00
Q3 2004	6	10.75	11.35	4.30	12.50
Q4 2004	5	10.91	11.48	4.17	14.40
Q1 2005	4	10.55	11.41	4.30	8.71
Q2 2005	12	10.13	11.49	4.16	13.70
Q3 2005	8	10.84	11.32	4.21	13.00
Q4 2005	10	10.57	11.14	4.49	8.44
Q1 2006	11	10.38	11.23	4.57	7.33
Q2 2006	18	10.39	11.38	5.07	8.83
Q3 2006	7	10.06	11.64	4.90	8.33
Q4 2006	12	10.38	11.19	4.63	8.11
Q1 2007	11	10.30	11.00	4.68	9.88
Q2 2007	16	10.27	11.44	4.85	9.82
Q3 2007	8	10.02	11.13	4.73	10.80
Q4 2007	11	10.44	11.16	4.26	8.75
Q1 2008	7	10.15	10.98	3.66	7.33
Q2 2008	8	10.41	10.93	3.89	10.80
Q3 2008	21	10.42	11.26	3.86	10.60
Q4 2008	6	10.38	11.21	3.25	11.90
Q1 2009	13	10.31	11.79	2.74	11.10
Q2 2009	22	10.55	11.01	3.31	9.13
Q3 2009	17	10.46	11.43	3.52	10.90
Q4 2009	14	10.54	11.15	3.46	9.69
Q1 2010	16	10.45	11.24	3.72	10.00
Q2 2010	19	10.12	11.12	3.49	9.00
Q3 2010	12	10.27	11.07	2.79	12.40
Q4 2010	8	10.30	11.17	2.86	10.90
Q1 2011	8	10.35	11.11	3.46	10.80
Q2 2011	15	10.24	11.06	3.21	12.00
Q3 2011	17	10.13	10.86	2.43	8.64
Q4 2011	10	10.29	10.66	2.05	7.60
Q1 2012	17	10.84	10.57	2.04	10.50
Q2 2012	16	9.92	10.66	1.82	11.40
Q3 2012	8	9.78	10.68	1.64	8.20
Q4 2012	12	10.05	10.69	1.71	8.65
Q1 2013	19	10.23	10.49	1.95	8.24
Q2 2013	16	9.77	10.40	2.00	11.80
Q3 2013	4	10.06	10.85	2.71	6.55
Q4 2013	7	9.90	10.24	2.75	8.14

NA = Not available
Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

The company also proposed a weather-normalized revenue decoupling mechanism for residential and small commercial customers and interim rate treatment for a coal plant that is returning to service after a technical problem.

Miscellaneous

Potomac Electric Power in Maryland filed in part because the company's earned ROE is only 6.69% (allowed ROE is 9.36%). Bangor Hydro Electric and Maine Public Service filed together. The companies merged into a single entity — Emera Maine — at the end of 2013, after the filing. They hope to recover costs relating to a new customer information system and vegetation management. Kansas City Power & Light in Kansas filed an "abbreviated" case; this is allowed by law in Kansas when the filing is made within 12 months of a rate case order and reflects "all the regulatory procedures, principles, and rate of return [parameters] established by the Commission."

Filed Cases in 2013

Storm Cost Recovery

Storm cost recovery figured prominently in rate case filings in 2013. United Illuminating filed in Connecticut in part to recover costs for storms since 2008. The company claimed $52 million in unfunded storm costs and proposed to draw on the customers' share of the company's earnings sharing mechanism for funding. The company proposed to recover $8.7 million of storm costs annually to amortize storm expense.

As part of Baltimore Gas and Electric's filing in Maryland the company proposed to implement an electric reliability investment (ERI) initiative and an associated tracker mechanism. Both are based on guidelines established as part of the commission's review of Maryland utilities' reliability performance and a governor's task force recommendation following a derecho storm. The ERI includes measures to be completed between 2014 and 2018 at an estimated cost of $136 million and is expected to improve the company's reliability by 10% compared to its average performance between 2010 and 2012.

Fitchburg Gas & Electric Light in Massachusetts filed to recover storm-related expenses and costs of reliability improvement, vegetation management and related enhancements. In addition, the company asked to implement a storm cost recovery factor.

Earned Return

Several companies filed cases in 2013 as a result of under-earning their authorized return, which can happen when regulatory lag prevents the company from catching up with rising expenses. Potomac Electric Power in its Washington, D.C. filing said it earned less than half of its authorized 9.5% ROE during the test year. Virginia Electric & Power said that its return had been reduced by 50 basis points by the retirement of six coal plants and by storm expenses. Baltimore Gas and Electric said that it expected to earn a 5.68% overall return for the year ending 7/31/2013.

ROE Decreases for Decoupling

Electric utilities during 2013 sought to eliminate ROE decreases imposed by commissions because the companies have decoupling programs. The commissions argued that decoupling decreases risk and the utility should therefore be awarded a lower ROE. The 10.25% ROE that Potomac Electric Power filed for in D.C. in 2013 did not reflect a 50-basis-point downward adjustment to reflect the company's decoupling mechanism. The company said the downward adjustment did not reflect current market conditions and was contrary to the vast majority of cases for decoupled utilities. Similarly, Delmarva Power & Light in its Maryland filing sought to dispense with the 50-basis-point reduction because it did not reflect current market conditions.

Low Growth

Low demand growth in the electric utility industry affected several filings in 2013. Lower sales volume in part drove Duke's filing in South Carolina. Sluggish revenue growth in part drove Tampa Electric's filing in 2013. And Baltimore Gas and Electric's filing references low customer growth.

Westar Kansas

Westar filed in Kansas for recovery of incremental costs, including construction work-in-progress, for an emissions control project at a coal plant. Among the many goals Westar hopes to achieve is a reduction in cross-class subsidies, an increase in the fixed monthly residential customer charge from $9 to $13, and an increase in the small general customer charge from $19 to $20.

Decided Cases in Q4

Monongahela Power West Virginia

In Q4, the West Virginia Commission approved a settlement for Monongahela Power that transfers generation assets to Monongahela from affiliated companies and implements a surcharge for generation recovery. The settlement also requires the company to hire 50 employees from West Virginia and contribute $500,000 over five years to each of the following: a low income assistance program, a weatherization program and a public school energy efficiency program. The settlement also requires the company to achieve, as part of an energy efficiency plan, 0.5% in energy savings by the year ending May 31, 2018 relative to 2013 delivery sales. Monongahela Power can recover the cost of the energy efficiency plan in rates, but the parties could not agree to recovery of lost revenue associated with the related decrease in sales.

Virginia Electric & Power

In Q4, the Virginia commission decided Virginia Electric & Power's legally mandated biennial earnings review case. Virginia state law requires that the commission determine a "fair" ROE based on the market cost of equity, a state-law-determined-peer-group ROE floor, and adjust for management performance, if necessary. Based on this formula, the company requested an ROE of 11.5%. The commission allowed 10%. The commission determined that "a market cost of equity of 10% fairly represents the actual cost of equity in capital markets for companies comparable in risk to Dominion seeking to attract equity capital. . . . We conclude that a market cost of equity of 10% is supported by reasonable proxy groups, growth rates, discounted cash flow methods, risk premium analyses and gradualism in ROE determinations." The company proposed a 55.624% equity component in its capital structure. The commission said the proposed equity component "is neither reasonable or prudent for the purpose of setting rates [because it:] 1) significantly exceeds the average equity ratio of its peers (including peers constructing nuclear plants); 2) is higher than necessary in order for [the company] to maintain reasonable credit ratings; 3) exceeds the company's own financial targets; and, 4) is higher than necessary for Dominion to raise capital on reasonable terms to its planned capital expenditures." The commission approved a 50% equity ratio. The commission also excluded $2.3 million in incentive compensation costs.

PacifiCorp Washington

In Q4, the Washington state commission rejected PacifiCorp's proposed power cost adjustment mechanism (PCAM), saying that the company failed "to demonstrate sufficient power cost variability to warrant approval for such a mechanism" and that the company did not design the mechanism in accordance with prior commission directives. The commission said "a properly designed PCAM includes dead bands and sharing bands so that the Company continues to bear some risk of under-recovery, and some opportunity to benefit from savings achieved via power cost management practices."

Baltimore Gas and Electric (BGE)

The Maryland commission approved five of eight proposals made by the company in relation to its Electric Reliability Investment initiative (ERI). The company developed this initiative (see also 2013 Filings above) in response to guidelines established in the commission's review of Maryland utilities' performance following a derecho storm in 2012. The company proposed an annual surcharge to recover costs associated with the initiative and crafted the surcharge to be consistent with recommendations by the Maryland Governor's Grid Resiliency Task Force. The company's eight proposals were: 1) expand the poorest performing feeder replacement program, 2) expand vegetation management, 3) improve the customer average interruption duration index (CAIDI), 4) expand recloser deployment on 13 kV distribution feeders, 5) expand recloser deployment on 34 kV lines, 6) diversify routing of 34 kV supply circuits, 7) implement selective undergrounding, and 8) improve substation reliability performance. The total cost for the initiative would have been $136 million between 2014 and 2018. Each surcharge would project costs through the coming year and true up at the end of the year. The commission approved 1, 4, 5, 6 and half of what the company proposed for 7. The commission said, "We respectfully disagree with those parties advocating that we wait until new [reliability] regulations are adopted, effective in 2016 and beyond, as the need to improve reliability is immediate and exigent. . . . what the Commission expects to see at the end of the five-year period, is a total improvement of over 12% in SAIDI [System Average Interruption Duration Index] and at least 3.7% in SAIFI [System Average Interruption Frequency Index]."

Two commissioners dissented on recovering ERI through a surcharge, saying that "approval of a surcharge is contrary to the precedent established by this Commission as well as sound regulatory policy. The surcharge will unfairly shift risks that are properly borne by the company shareholders to ratepayers, based on a multi-year forecast of plant that has not been demonstrated to be used or useful and estimated expenses that are not known and measureable. . . . we find the likelihood of 'claw back' of revenue of a future prudency review to be implausible."

BGE had also requested a 10.5% ROE, but the commission awarded 9.75%, as in BGE's previous case. The commission said that in the previous case it "determined that BGE was a low-risk investment based upon evidence it presented and past-market performance as a monopoly provider of electric and gas distribution service, its lack of ownership of any generating facilities, and its stable service territory with a BSA [decoupling] mechanism. Additionally, we found that the low interest rate environment that existed at the time . . . provided BGE with ample opportunity to obtain necessary capital at reasonable rates. The question in this case, therefore, . . . is, what has changed in less than one year . . . that now might justify a different return. BGE has not demonstrated any significant changes in the economic environment faced by the company." The commission noted that it had not adjusted the ROE downward as a result of its partial approval of the ERI.

The commission rejected a non-ERI adjustment for reliability-related projects, saying "such tools must be carefully constructed to insure ratepayer interests are protected in advance and that investments are cost effective. . . . we only allow recovery of post-test-year spending in rate base, if the plant investment is safety or reliability related, only if the amounts represent actual spending, and only if the amounts are known and measureable."

BGE also proposed to recover its major storm restoration expense over a three-year period, rather than the five-year period typically approved by the commission, because of the magnitude and frequency of major storms in recent years. The commission rejected the change, saying the company "has provided no demonstrable scientific evidence that the same frequency of major storms would continue in Maryland on any predictable basis, and that the five-year recovery period would not be sufficient. . . . in 2013 there have been no major storms."

Miscellaneous

In Gulf Power's case in Florida, the commission approved a settlement that authorizes an adjustment mechanism that permits the company to raise allowed ROE by 25 basis points if the 30-year U.S. Treasury bond yield increases by an average of 75 basis points above 3.7947% for a six-month period. In Ameren Illinois's case associated with the company's formula rate plan, the commission reduced the company's revenue requirement to account for revenue the company received as a result of its selling "vacated microwave frequencies" to telecommunication companies. The company argued that these frequencies had been used to transmit transmission data, and consequently were FERC jurisdictional. In Sierra Pacific's case in Nevada, the commission granted the company's demand side management investments a 500-basis-point return above authorized ROE and combined-cycle natural gas generation a 150-basis-point bonus return. In Upper Peninsula Power's case in Michigan, a settlement requires the company to spend $3.2 million on tree trimming and clear at least 1,760 miles of line or refund the difference to customers.

Decided Cases in 2013

ROE

In Kansas City Power & Light's subsidiaries' cases in Missouri, the companies originally requested a 10.4% ROE, later modified to 10.3%. The commission authorized 9.7%, in part because of "the downward trend in national averages of other state commissions' ROE awards, the continuing downward pressure on interest rates nationally, [and] the slower-than average recovery in Missouri."

In Michigan Power's case in Indiana, the commission awarded a 10.2% ROE as the mid-point of all the parties' recommendations, additionally finding that changes to the off-system sales (OSS) margin sharing mechanism and establishment of a storm reserve reduced the company's earning risk. The off-system sales mechanism was changed so that all variations are shared equally by customers and shareholders; the previous mechanism only shared amounts above a certain embedded amount with shareholders. The commission justified the different sharing mechanism as warranted by "market dynamics" and said that "sharing only the amount of sales in excess of the [embedded] amount and not any shortfalls does not fairly align the risk and reward of OSS sales between the company and ratepayers." The company had proposed a "fair value increment" to the revenue requirement to support its "continued financial resilience." This increment was calculated by applying an inflation-adjusted long-term Treasury bond yield to the difference between the company's fair value rate base and net original cost rate base. The company said that the commission's approval of the increment would "provide a clear signal that the Commission is willing to use the regulatory tools at its disposal to support [the company's] efforts to maintain investment-grade [credit] ratings and improve its credit standing by improving its ability to earn its allowed return." The commission concluded that the increment "artificially inflates the company's rates by arbitrarily increasing the amount of revenues [the company] is authorized to collect above that already calculated to provide a reasonable opportunity to earn its authorized return."

In Baltimore Gas and Electric's case in Maryland, the commission awarded the company a 9.75% ROE that reflected a downward adjustment of 50 basis points because the company has a decoupling mechanism. (For additional discussion of this issue for BGE, see Decided Cases in Q4 above.) BGE had argued that such an adjustment was not necessary because all the companies in the proxy group either had decoupling mechanisms or other revenue recovery mechanisms. The commission commented that, because another recent order prevented utilities from recovering lost revenues from storms through the decoupling mechanism, "a strict basis point reduction of 50 points may no longer be warranted," but the company's decoupling mechanism is "a 'very good' decoupling mechanism, better than almost all the others in any of the experts' proxy groups, which serves to limit the risk, and therefore the appropriate ROE, for BGE."

Indiana-Michigan Power (IM) Indiana

IM had proposed to include $6.2 million of storm restoration costs in its revenue requirement using a three-year average of these costs. The commission instead mandated a five-year average, at $4.2 million, but also allowed the company to implement a tracking mechanism for storm costs. The commission said "at times the cost of [storm] restoration may greatly exceed the amount of expense included in [the company's] revenue requirement. . . . that risk is traditionally borne by shareholders. In the past, the Commission has allowed a utility to seek recovery of extraordinary storm restoration expenses through a separate proceeding, but only when the storm at issue was a worst-case scenario. As we have recently seen, these stand-alone cases are often heavily litigated and highly contentious. Of course, the opposite situation also occurs, where the costs of storm restoration may be substantially less than the amount of the expense included in [the company's] revenue requirement. . . . the accounting [treatment] proposed by the Company . . . addresses both of these situations."

Baltimore Gas and Electric (BGE)

In the first of two cases decided for BGE during 2013 (for more on the second case see Decided Cases in Q4 above), the company argued that its use of a historical test year, along with rising costs, prevented it from earning its authorized return. Additionally, the company had planned more than $3 billion in capital expenditures over the next five years. As a result, BGE sought to include estimated post-test-year investments in rate base. BGE said the estimated costs meet the known and measureable test because the company is required to spend 95% of its planned capital expenditures and operation and maintenance expenses in 2012 and 2013 as a condition of its merger with Exelon. BGE also said it has shown a pattern of investment in safety and reliability and thus can easily estimate these costs. However, the commission found the proposal to include estimated post-test-year investments in rate base did not meet the known and measureable test, because it was "simply an estimate" and lacked sufficient support. The commission found the safety and reliability investment not used and useful or known and measureable and that "by the Company's own admission, estimates, forecasts, and budgets can prove unreliable."

Duke Energy Ohio
The Ohio commission authorized a settlement that grants Duke an $11 million vegetation management expense, the same amount the company spent in the test year, and a $4.4 million baseline expense for storms, but disallowed the company's requested storm deferral and tracking mechanism and any attempt to recover incremental expenses for 2012 storms. The company can request deferral of incremental storm costs after 2012. The settlement does not allow Duke's proposed rider to recover costs of facility relocation associated with mass transportation projects. Duke had claimed that, under pre-existing rates, it would earn a return of 4.79% on rate base. The commission said that such a rate of return is "insufficient to provide [the company] with reasonable compensation for the service it renders to customers."

San Diego Gas & Electric (SDG&E)
The California commission allowed SDG&E attrition rate increases for 2013-2015 based on changes in the Consumer Price Index-Urban, with some modifications. The commission authorized rate increases of 2.65% for 2013 and 2.75% for both 2014 and 2015. The commission also extended, subject to a $5 million deductible, the "Z-factor" mechanism that allows utilities to request recovery, under certain circumstances, for significant, unforeseen expenses between rate cases. The commission also allowed the company recovery of costs associated with the San Onofre Nuclear Generating Station, subject to refund pending a reasonableness review.

Maui Electric (MECO)
MECO entered into a settlement that would have authorized a 10% ROE, but the Hawaii commission reduced the ROE to 9%, because a 10% ROE would have fallen out of the 9% to 9.75% range proposed by the Division of Consumer Advocacy, one of the parties to the settlement. In addition, the commission said that half of the 100-basis-point adjustment was due, in part, to "updated economic and financial market conditions." The commission said that the second half of the adjustment reflected "apparent system inefficiencies which negatively impact MECO's customers. . . . [The company] appears to have failed to adequately and sufficiently plan for and implement the necessary modifications to its existing operations to accept a more appropriate level of wind energy generation made available to MECO, negatively impacting ratepayers through higher electricity rates." The commission said the order is intended to serve notice to MECO and other Hawaiian Electric utilities. The commission said the utilities "appear to lack movement to a sustainable business model to address technological advancements and increasing customer expectations. The commission observes that some mainland electric utilities have begun to define, articulate and implement the vision for the 'electric utility of the future.' Without such a long-term, customer-focused business strategy, it is difficult to ascertain whether [the Hawaiian Electric utilities'] increasing capital investments are strategic investments or simply a series of unrelated capital projects that effectively expand utility rate base and increase profits but [appear] to provide little or limited long-term customer value."

Miscellaneous
The Kansas City Power & Light utilities proposed to modestly increase customer charges, but the commission rejected the increases, saying, "Because volumetric charges are more within the customer's control to consume or conserve, the volumetric rate is the more appropriate to increase." In Tucson Electric Power's case, the commission did authorize increases in customer charges, including an increase in the residential customer charge from $7 to $10, saying the $10 charge was "a small part of the overall average bill of over $84" and well less than the $56 average monthly fixed costs per residential customer. In Potomac Electric Power's case in Maryland the commission denied the company recovery of $23.4 million in advanced metering infrastructure investment, saying that Pepco has yet to demonstrate that this investment is cost-effective. In Northern States Power's case in Minnesota, the increase allowed by the commission was less than the interim rates the company had implemented, and consequently the company owed customers a refund. In calculating the refund, the commission departed from its usual practice of using the average prime rate (3.25% in this case) in calculating the interest due customers, and instead used the overall rate of return (7.45%). In United Illuminating's case, the Connecticut commission rejected a 36% equity ratio capital structure proposed for the company by the Connecticut Industrial Energy Consumers (compared to a 50% ratio proposed by the company), saying "imposing such an extreme change . . . to the company's ratemaking capitalization mix may be disruptive to its financial stability and credit rating. . . . [We] will continue to monitor electric utility industry practices with regard to capitalization mix and will make changes to the ratemaking capital structure should industry standards change significantly."■

EN 23,24

FitchRatings

Fitch Affirms MEHC's & Subsidiaries Ratings; Outlook Stable; NNG Outlook Revised to Stable

Ratings Endorsement Policy

16 Sep 2013 2:02 PM (EDT)

Fitch Ratings-New York-16 September 2013: Fitch Ratings has affirmed MidAmerican Energy Holdings Co.'s (MEHC) Long-term Issuer Default Rating (IDR) at 'BBB+' and its Short-term rating at 'F2'. MEHC's individual security ratings have also been affirmed. Concurrently Fitch has affirmed the IDRs and individual security ratings for MidAmerican Funding LLC (MF), MidAmerican Energy Co. (MEC), PacifiCorp (PPW), and Kern River Funding Corp. (KRF).

Fitch has withdrawn the MEC Preferred Stock rating as there is no amount outstanding. The Rating Outlooks remain Stable.

Fitch has also affirmed Northern Natural Gas Co.'s (NNG) Long-term IDR and individual security ratings, and revised the Outlook to Stable from Negative.

A complete list of all rating actions follows at the end of this release.

KEY RATING DRIVERS

--Berkshire Hathaway, Inc. ownership strengthens group funding capabilities and capital retention.
--Ring-fencing by special purpose entities preserves operating company credit quality.
--Diversified low-risk regulated businesses support stable cash flows.
--Consolidated leverage remains high.
--Sufficient liquidity relative to funding needs.

MEHC Affirmation: MEHC's rating and Stable Outlook are supported by a large high-quality asset base, including two integrated regulated utilities, and two U.S. interstate gas pipeline systems. The ratings also consider Berkshire Hathaway, Inc.'s (BRK; IDR 'AA-'; Stable Outlook by Fitch) 90% ownership of the company which Fitch views as being beneficial to MEHC's credit quality. The company retains capital as a direct result of BRK's financial strength, which obviates the need to upstream dividends and affords MEHC an advantage in funding organic growth and acquisitions such as PPW in 2006 and the pending acquisition of NV Energy, Inc. (IDR 'BB+'; Credit Watch Positive).

Consolidated Financial Metrics: Relative to historical performance financial metrics are improving. EBITDA-to-interest, as calculated by Fitch, was 3.5x for the latest twelve month (LTM) period ended June 30, 2013, and forecast by Fitch to reach 4x over the five-year forecast period. Cash flows are likely to weaken as the positive benefits from bonus depreciation, production tax credits (PTCs)and investment tax credits (ITCs)are lower in the forecast period. Funds from Operations (FFO) interest coverage for the LTM period ended June 30, 2013 was 4.6x and is forecast by Fitch to be at, or below 4x toward the end of the five-year forecast period.

Fitch's forecast assumes the pending acquisition by MEHC of NV Energy is complete in 2014 at which time the proportion of consolidated earnings contributed by regulated utility business will be approximately 70%; and, higher than 90% including the pipeline businesses.

High Leverage: Debt-to-EBITDA for the LTM period ended June 30, 2013 was 5.3x. The anticipated impact of the $5.6 billion acquisition of NV Energy could keep leverage metrics elevated through 2015. Fitch considers any acquisition financing provided by BRK to be 'equity like'. Absent the NV Energy acquisition, Fitch forecast debt-to-EBITDA to range near 4.4x toward the end of the five-year forecast.

Sufficient Liquidity: MEHC's consolidated liquidity position at June 30, 2013 was $5.16 billion, including $892 million in available cash. This figure includes a $2,000 million equity commitment agreement (ECA) provided by BRK to MEHC through February 2014. MEHC stand-alone bank credit is $600 million, and the credit facility matures in 2017. Bank credit supports the company's commercial paper (CP) program. Single bank concentration is not a concern as the largest single bank concentration is 8%.

Fitch considers MEHC and subsidiaries' access to the bank credit and debt capital markets unrestricted. MF/MEC stand-alone credit includes a $600 million bank credit facility which matures in 2018. PPW stand-alone credit is $1.2 billion with facility maturities in 2017 and 2018.

MF/MEC Ratings Affirmed: The ratings affirmations are based on the credit quality of MEC, an integrated regulated electric utility. MF is an intermediate holding company owned by MEHC, and indirect holding company of the utility. MEC's rating and Stable Outlook reflects the company's relative low business risk profile, solid financial metrics, and a constructive regulatory environment in Iowa.

Fitch expects financial metrics to remain consistent relative to guidelines for the risk profile and ratings, with MF EBITDA-to-interest and FFO-to-debt to range between 4.5 - 5.2x and approximately 21%, respectively through 2017. The same metrics for MEC are forecast to range between 5.1x - 5.7x and lowers to 23%, respectively over the five-year forecast period. Fitch attributes current higher levels of FFO to bonus depreciation and PTCs for wind generation.

MEC has a new rate filing pending with the Iowa Utilities Board (IUB), with interim rates in effect in August 2013 and new rates effective in 2014. The utility has proposed an energy adjustment clause to capture changes in retail fuel costs, environmental consumables and allowances, and pretax changes in PTCs. The utility also included in its filing a transmission rider to recover Midcontinent Independent System Operator (MISO)-billed costs. Fitch's assumes a fair outcome.

PacifiCorp Ratings Affirmed: The utility's rating and Stable Outlook reflects PPW's low business risk profile, competitive resource base, solid financial metrics, and a fairly balanced and diversified regulatory environment. PPW operates in six state jurisdictions, Utah, Wyoming, Idaho, Oregon, Washington and California. Ratings stability is predicated on reasonable outcomes in pending and future rate proceedings to recover anticipated, significant capital investments.

A key rating concern is the execution of a large capital plan and timely recovery of related costs. Also a concern is the potential for more stringent environmental rules and regulations. Over the next five years capital spending will reach $6 billion, $2 billion less than Fitch's previous assessments, largely due to a scale back by management to reflect lower forecast load growth. The revised plan reflects delays starting certain generation and transmission projects and supports a stable credit profile. Higher spending levels could expose the utility to increased regulatory recovery which may weaken financial metrics over a capital intensive period.

Rate treatment is fair and well-diversified across multiple state jurisdictions. Exposure to commodity price risk is largely mitigated by power adjustment mechanisms in five of the six rate designs. Other rate features allow for the recovery or deferral for future recovery of investments in renewable generation, or other investments outside traditional rate filings. PPW has rate filings pending in Oregon and Washington. Fitch's rating assessment assumes fair outcomes in each.

NNG Outlook Revised to Stable: The Outlook revision reflects Fitch's assumption that the $100 million maturity due in 2015 will be paid-in full effectively reducing pro-forma leverage metrics. Fitch forecasts debt-to-EBITDA at or near 2.5x for a sustainable period starting in 2015. Fitch also considers re-contracting will be supportive of a Stable Outlook.

Absent re-payment in full of the maturity and/or a narrowing of basis differentials, which would have a negative impact on interruptible transportation prices, Fitch could expect to see leverage metrics at levels higher than 2.8x which could result in negative rating action.

The Stable Outlook for NNG reflects the pipeline's strong business profile as an essential supplier of natural gas to many Midwest utilities under long-term contracts, favorable operating characteristics, and low regulatory risk.

KRF Ratings Affirmed: KRF ratings reflect Fitch's assessment that the pipeline produces predictable cash flows, receives fair rate treatment by the FERC, and capital spending levels remain manageable. Fitch views debt amortization as a key driver of improving leverage metrics over the five-year forecast period. The pipeline serves the Salt Lake City, UT areas, Southern Nevada and Central California.

RATING SENSITIVITIES

Future developments that may, individually or collectively, lead to a positive rating action include:

--MEHC: High leverage at the consolidated level continues to limit positive rating action;

--MF: If MF were to redeem its parent level debt its long-term IDR would likely be raised to that of MEC;

--MEC: The already strong rating of the utility limits positive rating action at this time;

--PPW: If FFO-to-debt were to increase and be sustained at or near 20%;

--NNG and KRF: The already strong ratings limit positive rating action at this time.

Future developments that may, individually or collectively, lead to a negative rating action include:

--MEHC: A change in ownership would have negative implications on the company's credit ratings; and/or a material change in financial policies including dividends from MEHC to BRK would pressure financial metrics;

--MF and MEC: If FFO-to-debt were to decrease and be sustained below 20%.

--PPW: If FFO-to-debt were to decrease and be sustained below 16%;

--NNG: Higher pro-forma leverage that could result in weakened leverage metrics over a longer period than considered by Fitch in its rating forecast could result in negative rating action;

--KRF: Negative rating action is unlikely at this time.

Fitch has affirmed the following ratings with a Stable Outlook:

MidAmerican Energy Holdings Co. (MEHC)
--Long-term IDR at 'BBB+';
--Senior unsecured debt at 'BBB+';
--Preferred stock at 'BBB-';
--Short-term IDR at 'F2'.

MidAmerican Funding LLC (MF)
--Long-term IDR at 'BBB+';
--Senior secured debt at 'A-'.

MidAmerican Energy Company (MEC)
--Long-term IDR at 'A-';
--Senior secured debt at 'A+';
--Senior unsecured debt at 'A';
--Short-term IDR at 'F1';
--Commercial paper at 'F1'.

Fitch has withdrawn the Preferred Stock rating at 'BBB+'.

PacifiCorp (PPW)
--Long-term IDR at 'BBB';
--Senior secured debt at 'A-';
--Senior unsecured debt at 'BBB+';
--Preferred stock at 'BBB-';
--Short-term IDR at 'F2';
--Commercial paper at 'F2'.

Kern River Funding Corp. (KRF)
--Long-term IDR at 'A-';
--Senior unsecured debt at 'A-'.

Fitch has affirmed the following ratings and revised the Outlook to Stable from Negative:

Northern Natural Gas Co. (NNG)
--Long-term IDR at 'A';

--Senior unsecured debt at 'A'.

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Applicable Criteria and Related Research:
--'Corporate Rating Methodology' (Aug. 8, 2012);
--'Rating North American Utilities, Gas and Water Companies'
(May 16, 2011);
--'Recovery Ratings and Notching Criteria for Utilities' (Nov. 13, 2012);
--'Corporate Rating Methodology: Including Short-term Ratings and Parent and Subsidiary Linkage' (Aug. 5, 2013).

Applicable Criteria and Related Research:
Corporate Rating Methodology - Effective from 8 August 2012 - 5 August 2013
Rating North American Utilities, Power, Gas, and Water Companies
Recovery Ratings and Notching Criteria for Utilities
Corporate Rating Methodology: Including Short-Term Ratings and Parent and Subsidiary Linkage

Additional Disclosure
Solicitation Status

FIS 25

MOODY'S
INVESTORS SERVICE

Credit Opinion: PacifiCorp

Global Credit Research - 08 May 2013

Portland, Oregon, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
Senior Secured	A2
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured MTN	(P)Baa1
Pref. Stock	Baa3
Commercial Paper	P-2
Ult Parent: Berkshire Hathaway Inc.	
Outlook	Stable
Issuer Rating	Aa2
Senior Unsecured	Aa2
ST Issuer Rating	P-1
Parent: MidAmerican Energy Holdings Co.	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Commercial Paper	P-2

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Key Indicators

[1]PacifiCorp	2012	2011	2010	2009
(CFO Pre-W/C + Interest) / Interest Expense	4.9x	4.8x	5.3x	5.2x
(CFO Pre-W/C) / Debt	21.1%	21.0%	25.7%	26.0%
(CFO Pre-W/C - Dividends) / Debt	18.4%	13.5%	25.7%	26.0%
Debt / Book Capitalization	38.3%	39.8%	38.8%	42.4%

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Reasonably supportive regulatory environment

Diversification to mitigate exposures to environmental spending, economic cycles

Solid credit metrics

Benefits from Berkshire Hathaway affiliation

Corporate Profile

PacifiCorp (Baa1 senior unsecured, stable) is a vertically integrated electric utility company headquartered in Portland, Oregon serving 1.8 million retail electric customers in six states, including Utah (44% of PacifiCorp's 2012 retail electricity volumes), Oregon (23%), Wyoming (17%), Washington (7%), Idaho (7%), and California (2%). PacifiCorp also has ancillary operations in wholesale power marketing (18% of 2012 electricity volumes, as a result of excess electricity generation or other system balancing activities) and coal mining services, both which support its core utility business.

PacifiCorp is the largest subsidiary of MidAmerican Energy Holdings Company (MEHC: Baa1 senior unsecured, stable), accounting for roughly 40% of MidAmerican's operating income in 2012. MEHC, in turn, is a consolidated subsidiary of Berkshire Hathaway Inc. (BRK: Aa2 Issuer Rating, stable).

SUMMARY RATING RATIONALE

PacifiCorp's ratings are supported by the stability of the utility's regulated cash flows, the geographically diverse and relatively constructive regulatory environments in which it operates, the diversification of its generation portfolio, and solid credit metrics. The rating also considers PacifiCorp's position as a subsidiary of MEHC, a holding company whose subsidiaries are primarily engaged in regulated activities, and the benefits from its affiliation with BRK.

DETAILED RATING CONSIDERATIONS

Reasonably supportive regulatory environment

PacifiCorp's rating recognizes the rate-regulated nature of its electric utility operations which generate stable and predictable cash flows. PacifiCorp operates in regulatory jurisdictions that Moody's considers as average in terms of framework, consistency and predictability of decisions along with an expectation of timely recovery of costs and investments. This "average" assessment is in line with Moody's views of most US state jurisdictions compared to regulatory environments elsewhere in the world.

Regulatory lag is a challenge for PacifiCorp, which has long maintained large capital programs to meet load growth as well as regulatory requirements for emissions control, renewable standards, and reliability. Although PacifiCorp has been filing rate cases every year or so in its largest jurisdictions and getting reasonable outcomes, the large capital investments cause its actual returns on equity to be in the 7%- 8% range compared to the roughly 10% that it is allowed.

Expecting weak load growth over the next decade, the company has cut future capital expenditures to roughly $1.1 billion a year, down considerably from the $1.5 billion it has spent in recent years. Almost half of the reduction is in generation. Less capital spending will reduce the need for rate relief and, consequently, regulatory lag.

The most significant of the 2012 rate orders was in Utah, by far its biggest jurisdiction, where $154 million in rate increases (8.5%) will be staged in over 2 years. Sizable rate cases have been filed in Oregon and Washington in Q1 2013, requesting increases of $56 million (5%) and $43 million (14%), respectively. These cases should be decided by year-end 2013.

Future rate filings will arise from its $6 billion Energy Gateway transmission program, with multiple segments currently under construction, and its Lake Side 2 gas plant, which is expected to come online in 2014. The ability to use a forward test year in its rate requests helps to limit regulatory lag in Utah, Oregon, Wyoming, and California. The company has been successful in getting approvals for its major projects; however, it is exposed to some disallowances in most of its jurisdictions, where pre-approvals on projects or cash returns on construction work in progress are not granted.

The company has obtained energy cost adjustment mechanisms in all its jurisdictions now except Washington. Such mechanisms to recover fuel and purchased power costs -- a large, volatile expense --are more established in other parts of the country. While this development is supportive of credit quality, there remains some lag in recovering portions of energy costs. For example, in Utah, Wyoming, and Idaho, the majority of the difference between the actual power costs and costs established in its base rates is deferred. This difference is then recovered or refunded after an annual filing.

Diversification to mitigate exposures to environmental spending, economic cycles

PacifiCorp benefits from a well diversified generation portfolio. Its 11,224 MW of net generating capacity is comprised primarily of its low cost base-load coal plants (55% of the company's generation), along with 25% from its gas assets and 10% from hydro.

With coal accounting for a slight majority of its generation capacity, PacifiCorp is subject to numerous emissions standards, but the company is well positioned to comply with the vast majority of its plants already equipped with sulfur dioxide and nitrogen oxide controls.

Reflecting a common strategic imperative among MEHC affiliates, PacifiCorp has been investing heavily to increase its non-carbon generation resources, and in so doing, has become the second-largest utility owner of wind generation facilities in the US. Owning this much wind capacity not only mitigates exposure to stricter environmental rules for coal plants, but also helps in meeting ambitious renewable portfolio standards in Oregon, Washington, and California.

The market and customer diversity of PacifiCorp's six-state service territory is favorable, because it mitigates the economic and regulatory impacts in any one jurisdiction. This benefit is demonstrated by the recent economic impact on retail sales. Load has been declining for five straight years in the Pacific Northwest from still weak industrial demand, while the Rocky Mountain states have enjoyed some commercial and industrial growth from oil and gas activity, which has been offset by self-generation among its industrial customers.

Solid credit metrics

PacifiCorp's overall key credit metrics in 2012 mapped to the low A range in the Regulated Utilities Methodology. The ratio of cash from operations before changes in working capital (CFO pre-W/C) to Debt, calculated in accordance with Moody's standard adjustments, was unchanged from 2011 at 21%, compared to 26% in both 2010 and 2009. Its CFO pre-W/C interest coverage was 4.9x in 2012 versus 4.8x in 2011and the 5x range in 2010 and 2009.

PacifiCorp's credit metrics - like the rest of the utilities industry - have been buoyed by the effects of bonus depreciation, a temporary tax benefit which will extend through 2013. Normalized to exclude bonus depreciation, CFO pre-W/C to Debt would have been in the upper-teens and CFO pre-W/C interest expense coverage would have been in the mid to lower 4 times range during 2009-2011. After bonus depreciation ends in 2013, PacifiCorp's credit metrics will return to more normal, sustainable levels.

Benefits from Berkshire Hathaway affiliation

PacifiCorp paid dividends of $200 million to MEHC in 2012, and $550 million in 2011, which was its first since being acquired by MEHC in 2006. MEHC had made equity contributions in each of the previous five years totaling $1.1 billion to help PacifiCorp finance its capital expenditures during this period. The dividends were intended to manage PacifiCorp's equity ratio (as measured by unadjusted equity to equity plus debt) around 50% after it had accreted to 53% as of year-end 2010. PacifiCorp is not held to a regular dividend, but will likely make additional dividends periodically, depending on its capital requirements and equity ratio.

From a credit perspective, the company's ability to retain its earnings as an entity that is privately held, particularly by a deep-pocketed sponsor like BRK, is an advantage over most other investor owned utilities that are typically held to a regular dividend to their shareholders. An additional tangible benefit from PacifiCorp's BRK affiliation is an equity commitment agreement, expiring on February 28, 2014, between MEHC and BRK, under which BRK has committed to provide up to $2 billion through February 2014. Equity from this agreement may be requested to fund MEHC's debt obligations or to provide capital to MEHC's regulated subsidiaries, including PacifiCorp. This agreement thus provides PacifiCorp with an additional source of alternate liquidity. We do not expect the commitment to be renewed, thus somewhat weakening the liquidity profile in 2014 and beyond, but we see no reason why BRK would not be supportive in the event of extraordinary and unanticipated difficulty at MEHC.

Liquidity Profile

PacifiCorp has good near-term liquidity, with $133 million in cash and two $600 million revolvers expiring in 2017 and 2018, of which about $888 million was available as of March 31, 2013. In 2012, the company generated cash flow from operations before working capital changes of $1.5 billion which will more than cover the $1.1 billion a year it plans on capital expenditures. Excluding minor amounts of revenue bonds, significant upcoming debt maturities include $200 million due on September 15, 2013 and $200 million due on August 15, 2014. The roughly $400 million reduction in annual capital expenditures will reduce the need for long and short term borrowings.

PacifiCorp uses its credit facilities to backstop its commercial paper program and to support its variable rate tax-exempt bonds. These credit agreements do not a require MAC representation for borrowings, which Moody's views positively. The sole financial covenant is a limitation on debt to 65% of total capitalization. As of March 31, 2013, PacifiCorp had ample headroom under that covenant with that ratio at 47% as defined in the agreement.

Rating Outlook

The stable outlook incorporates Moody's expectation that PacifiCorp will continue to receive reasonable regulatory treatment for the recovery of its capital expenditures, and that the funding requirements will be financed in a manner consistent with management's commitment to maintain a healthy financial profile. After the bonus depreciation ends in 2013, Moody's anticipates that PacifiCorp's credit metrics will return to the levels more typical before 2009, with CFO pre-W/C to Debt just below 20%.

What Could Change the Rating - Up

While the size of the company's capital expenditures limits the prospects for a rating upgrade in the near-term, the rating could be upgraded if reasonable regulatory support and a conservatively financed capital expenditure program results in a sustained improvement in credit metrics. This would include, for example, PacifiCorp's ratios of CFO pre-W/C to Debt sustained in the mid 20% range.

What Could Change the Rating - Down

The ratings could be adjusted downward if PacifiCorp's planned capital expenditures are funded in a manner inconsistent with its current financial profile, or if there were to be adverse regulatory rulings on current and future rate cases such that we would anticipate a sustained deterioration in financial metrics as demonstrated, for example, by a ratio of CFO pre-W/C to Debt falling to the mid teens.

Rating Factors

PacifiCorp

Regulated Electric and Gas Utilities Industry [1][2]	**12/31/2012**		**Moody's 12-18 month Forward View* As of May 2013**	
	Measure	Score	Measure	Score
Factor 1: Regulatory Framework (25%)				
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (5%)		A		A
b) Generation and Fuel Diversity (5%)		Baa		Baa
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		A		A
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	5.0x	A	4.5x-4.9x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	22.5%	A	18%-	Baa

d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	19.0%	A		20% 16%-18%	A
e) Debt/Capitalization (3 Year Avg) (7.5%)	39.0%	A		36%-39%	A
Rating:					
a) Indicated Rating from Grid		Baa1			Baa1
b) Actual Rating Assigned		Baa1			Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2012(LTM); Source: Moody's Financial Metrics

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JUNE 18, 2010

MOODY'S
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SPECIAL COMMENT

Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality

Evaluating a Utility's Ability to Recover Costs and Earn Returns

Table of Contents:

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Summary

A utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings. In Moody's Regulated Electric and Gas Utilities Rating Methodology, published in August 2009 (the Rating Methodology), these concepts are incorporated as the second of four key factors utilized to determine credit ratings in the regulated utility sector. The criteria we consider when analyzing this factor include the statutory and regulatory provisions in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery of costs, precluding any possibility of legal challenges to rate increases or cost recovery mechanisms. Such strong statutory protections are most often found in very supportive and protected regulatory environments like Japan and Hong Kong, for example. In the U.S., however, the ability to recover costs and earn returns is much less certain and can be subject to intense public and sometimes political scrutiny, and such provisions vary among state jurisdictions. Consequently, the analysis of a U.S. based utility's cost recovery and return provisions is more complicated. This Special Comment discusses the criteria we use to determine how a utility is scored in the cost recovery and return factor in our ratings methodology.

One of the most referenced, but potentially misleading, indicators used to judge whether a particular utility is recovering its costs and earning an adequate return is its regulatory allowed return on equity. Although a high allowed return on equity can be associated with a higher earned return, this measure cannot be looked at in isolation but must be viewed in relation to a utility's cost recovery provisions that impact actual earned rate of return, like automatic adjustment clauses, the length of rate cases, and the degree of regulatory lag that may occur. Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risk of a utility, providing justification for a relatively low allowed rate of return. We believe this is one of several reasons why both allowed and requested ROE's have trended downward over the last two decades.

Moody's views automatic adjustment clauses, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk. Fuel adjustment clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. Many of these clauses are annual but they can also be semiannual, quarterly, or monthly. The scope of automatic adjustment clauses has expanded over the years and now covers costs as diverse as transmission, generation, renewable energy, environmental compliance, pensions and bad debt. Generally, the more of these clauses a utility has in place, the stronger its scoring should be on this ratings factor and the lower the credit risk.

Other considerations when analyzing cost recovery include the test year used, regulatory pre-approvals, and the inclusion of construction work in progress (CWIP) in rate base. Forward test years are generally better predictors of future utility conditions than historical test years, and their usage is more likely to reduce regulatory lag. Regulatory pre-approval of major capital expenditures, especially for large, complex projects like new nuclear plants, are also important in the maintenance of utility credit quality. Similarly, the inclusion of CWIP in rate base provides greater regulatory certainty, reduces the chance of rate shock or regulatory disallowance at the end of the construction period, and helps moderate financial pressure on a utility during a capital build cycle. Some of these concepts require a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service.

Other cost recovery related factors Moody's considers to be favorable to utility credit quality include granting of interim rate relief, which we view as an effective way to accelerate the lengthy and cumbersome rate case process, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. Decoupling mechanisms to "de-link" utility revenues and profits from volumes are essential to credit quality if energy efficiency and demand side management programs become more prevalent in the sector as anticipated. Finally, the option to issue cost recovery bonds to securitize large or unexpected costs, like those from storms, is another way that a utility can recover its costs and avoid the rate shock that could result if such costs are passed on to ratepayers over a limited time frame.

Introduction

In Moody's Rating Methodology, the cost recovery provisions a utility has in place, as well as the return it earns, are important determinants of a utility's rating and overall credit quality. These concepts are incorporated into the ratings methodology as the second of four key factors we use to determine ratings in the regulated electric and gas utility sector. A utility's ability to recover its costs and earn a return represents a significant 25% of the overall weighting[1] of the factors used to determine a utility's credit rating. Unlike Factor 1, Regulatory Framework, which considers the general regulatory environment under which a utility operates and the overall position of a utility within that regulatory environment, Factor 2 addresses in a more specific manner the ability of an individual utility to recover its costs and earn a fair return on invested capital.

1 The factor weightings shown in the rating methodology grid are approximate. The actual weight given to a factor in our assessment of an issuer's credit quality may differ based on the issuer's circumstances, and the scoring does not include every consideration that determines a rating.

TABLE 1

Regulated Electric and Gas Utility Rating Methodology

KEY RATING FACTORS AND WEIGHTINGS
1. Regulatory Framework – 25%
2. Ability to Recover Costs and Earn Returns – 25%
3. Diversification – 10%
4. Financial Strength and Liquidity – 40%

The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated electric and gas utilities, especially since the lack of timely recovery of costs has caused severe financial stress for utilities on several occasions. In five of the seven major investor owned utility defaults in the United States over the last 50 years, regulatory disputes culminating in insufficient or delayed rate relief for the recovery of costs and/or capital investments ultimately led to financial pressure and credit rating downgrades. The reluctance to provide rate relief in some cases reflected regulatory commission concerns about the impact of large rate increases on customers as well as concerns about the appropriateness and prudency of the relief being sought by a utility. Currently, given the utility industry's sizable capital expenditure requirements for infrastructure needs and environmental compliance, there is likely to be a growing and ongoing need for rate relief to recover these expenditures, at a time when economic conditions may limit the ability or willingness of regulators to provide this timely rate relief. Regulators also need to balance the amount of rate relief granted to utilities with consumers' ability to absorb these costs.

For regulated utilities, the criteria we consider in assessing Factor 2 include the statutory protections in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan and Hong Kong, for example.

More typically, however, and as is characteristic of most utilities in the U.S. and elsewhere in Asia, the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost adjustment clauses or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score in the A category for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa score for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

Most of the utilities in Central and Eastern Europe (CEE) inherited oversized, outdated and underinvested infrastructure, built during previous communist regimes. Furthermore, those infrastructure assets are very often highly depreciated. Therefore, the main regulatory challenges for the CEE region lies rather in the area of full recovery of investment costs, including the establishment of appropriate regulatory asset bases and the determination of reasonable regulatory depreciation levels (which would be included in allowable costs to be recovered), rather than fine-tuning the actual level of return. Indeed, there is a very similar issue confronting South Africa, where there has been a long period of underinvestment in electricity assets. The approach towards the determination of the regulated asset base and treatment of asset revaluations differ significantly across the developing markets and could impact utilities' ability to generate sufficient funds for future investment in new assets.

The following is a discussion of the key factors we consider when scoring Factor 2, "Ability to Recover Cost and Earn Returns", in our Rating Methodology. The current Factor 2 scoring for the operating utilities in our rated universe is shown in Appendix A. These Factor 2 scores provide in indication of our current thinking. The scores are not intended to be static and continue to be monitored and modified as warranted to reflect changing conditions and circumstances, particularly as new rate cases are decided and cost recovery provisions evolve. In addition, when applied within the context of the Rating Methodology framework grid, the scores shown in Appendix A may be further modified by the use of a "strong" or "weak" designation.

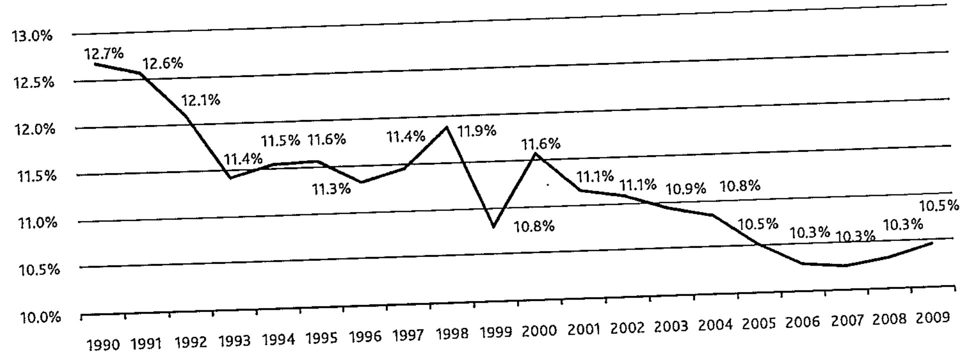
Return on Equity and Regulatory Lag

A utility's allowed return on equity (ROE) is one of the most obvious but potentially misleading statistics used to judge if a utility is recovering its costs and earning an adequate return. High ROE's are typically better than low ROE's, one reason that the timely, forward looking regulation of the Federal Energy Regulatory Commission (FERC) is viewed as more supportive, with ROE's that can be 12% or higher. In theory, if a utility's allowed return on equity is set at a high level, its earned return should also be high, leading to higher equity values, lower costs in relation to revenues, and ultimately higher credit ratings. This framework exists for some investor owned utilities, with high ROE's equating to good earnings and strong metrics, although this is not always the case. Earned ROE's are important in that they help to measure management's ability to operate their utility system within a given regulatory structure. A low allowed ROE is often associated with low earned ROE's, thereby affecting net income, lowering retained cash flow, depressing equity values, and raising financing costs.

However, the relationship between a utility's allowed return on equity and its ability to recover its costs and earn an adequate return is not as simple or clear cut as it may appear. A utility may have a low allowed ROE but be permitted to recover many of its operating costs through automatic adjustment clauses and other trackers, reducing risk and mitigating the impact of a low ROE. On the other hand, a utility may be permitted a high allowed ROE, but because of the higher than average risks associated with operating within this jurisdiction, the absence of such cost recovery provisions, overly long rate cases, or significant regulatory lag, may never actually earn its allowed return. According to the Edison Electric Institute, the average regulatory lag in the utilities industry is 11 months, close to where it has been for most of the last two decades. Adequate liquidity reserves on the part of utilities should mitigate some of the risks associated with regulatory lag.

While it is important to establish a link between a utility's regulatory allowed ROE and its automatic adjustment cost recovery clauses, it is also important to associate its authorized ROE with the sales forecast underlying the return. On its face, a high allowed ROE may appear favorable, although the return may be premised on a historic test year in which a high level of sales was achieved, which may not reoccur. This scenario could occur if there is a subsequent economic recession, unexpected financial shock, or lower usage on the part of the utility's customers due to high electric and/or gas rates or energy conservation. In such a case, a utility with a higher allowed ROE may be no better positioned than a utility with a lower allowed ROE based on a more achievable sales forecast. Allowed ROE's generate headline news, and market participants often gauge, at first blush, a utility's treatment in a rate case by this measure. However, the allowed ROE should not be viewed in isolation, but must be evaluated within the context of a utility's overall cost recovery provisions.

FIGURE 1
Average Awarded Electric ROE



Source: Regulatory Research Associates, a subsidiary of SNL Financial ,LLC, Edison Electric Institute

While regulatory lag has been stable, the long-term trend in allowed ROE's over the last two decades has been down, with the average allowed ROE falling from the 12% to 13% range in the early 1990's to the 10% to 10.5% range in recent years. In some cases, utility allowed ROE's have dropped below 10%. Not surprisingly, the average requested ROE has exhibited a similar trend, falling from as high as 13.5% in the early 1990's to approximately 11.2% in the first quarter of 2010. While some of the decrease in ROE's can be attributed to falling interest rates over the period, some can also be attributed to the other mechanisms that utilities have put in place to ensure timely cost recovery and maintain adequate returns, many of which are discussed below.

Some regulators view mechanisms such as cost recovery provisions and other automatic cost adjustment clauses as materially reducing the business and operating risk of some utilities, thereby justifying a lower return on equity. While there may be some merit to this argument, the relationship between these mechanisms and return on equity is complicated. Many of these provisions are "earnings neutral" but can have a cash impact, positive or negative, which could affect cash flow coverages and credit quality. Similarly, the increasing prevalence of formula based ratemaking and formula rate plans, where capital projects and other major revenue based changes are automatically incorporated into rates, have also caused some regulatory commissions to approve lower ROE's. However, a well structured formula rate plan could also lead to rate reductions if a utility is earning above its allowed range and in such cases, a lower allowed ROE may not be justified. Using ROE alone as a basis to compare utilities that operate under varying conditions and in different regulatory environments can be problematic and overly simplistic. Other considerations that may lead to widely different ROE's among utilities include the type of utility (whether vertically integrated or transmission and distribution), the mix of plants it operates, the size of its capital expenditure program, the risks associated with operating in a certain jurisdiction or building certain assets, demand and economic conditions within its service territory, and the utility's overall balance of debt and equity.

Fuel, Purchased Power and Other Automatic Cost Adjustment Clauses

Among the most common cost recovery provisions in the regulated utility sector are automatic adjustment clauses and other cost trackers (also referred to as riders or true-ups) for the recovery of costs outside of traditional base rate cases. The most prevalent type of such clauses are fuel adjustment clauses (FAC's) in the electric sector and purchase gas adjustments (PGA's) in the gas sector. These generally permit automatic changes in rates in response to movements in the price of fuels used in the generation of electricity and in the price of purchased gas for local distribution companies. Moody's views automatic adjustment clauses as supportive of utility credit quality and important in reducing utility cash flow volatility and liquidity requirements. These clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. They also reduce the level of regulatory uncertainty for the recovery of these costs by ensuring, through regulatory or statutory means, their recovery up-front.

Important considerations when analyzing such clauses include the frequency of true-up calculations and the period of time over which revenue variances are recovered. For example, Consolidated Edison Company of New York's purchased power cost variances are calculated monthly and recovered or refunded generally within one or two months. Some gas LDC's have quarterly gas cost adjustments; some vertically integrated utilities calculate fuel variances annually and recover these costs the following year, while others may recover some costs over a longer time period. In general, more frequent variance calculations and shorter recovery periods are considered more supportive of credit quality, limiting the potential for the accumulation of large deferral balances, the recovery of which could result in rate shock for consumers, as well as liquidity and working capital stress.

Adjustment Clauses as Regulatory Policy

Fuel adjustment clauses became prevalent in the U.S. in the 1970's when dramatically higher oil prices severely affected the cash flows of several utilities, when the industry was much more reliant on oil as a source of fuel for generation than it is today. During this time, oil prices rose so quickly that traditional base rate proceedings, with their lengthy time schedules, were unable to address cost recovery in a timely manner, severely stressing the cash flows of several utilities. Since that time, most U.S. states have permitted their utilities to automatically adjust fuel related rates outside of a formal base rate proceeding. In Missouri, one of the few states that historically did not have a fuel adjustment clause, legislation was passed in 2005 permitting the Missouri Public Service Commission to implement such a clause. In Ohio, fuel recovery was recently granted to AEP's Ohio Power subsidiary, although Duke Energy Ohio has had one in place for years.

Volume risk and purchase cost adjustments emerged as important regulatory topics in Central and Eastern Europe (CEE) only after the increase in the volatility of energy prices and unprecedented declines of energy consumption caused by the recent recession. The approach of respective CEE regulatory bodies varied from strong opposition to timely adjustments, mostly motivated by social considerations (i.e. Poland, Slovakia), to incorporation of automatic fuel and purchase adjustment mechanisms into regulation. Surprisingly, the regulatory regimes of Baltic countries, where the recession took the greatest toll, showed relatively solid resilience to political interference and allowed the local dominant electric utilities (the Latvian Latvenergo and the Estonian Eesti Energia) to pass through costs from fluctuating fuel input prices, thus allowing them to generate sufficient cash flows even in times of significant economic readjustment; this justifies their scoring of A in this factor.

In Korea, KEPCO's financial performance suffered significant deterioration in 2008 as a result of exposure to contracted high fuel costs and sharp depreciation of the Korean Won. The government stepped in and approved a 4.5% tariff increase and a KRW668 billion one-off subsidy to offset its losses due to high fuel costs and currency devaluation. The government is also considering implementing an automatic cost pass through mechanism in due course.

Automatic adjustment clauses are typically aimed at mitigating the effects of highly variable costs, such as fuel and purchased power, which are typically the largest component of utility operating expenses. These costs have been particularly volatile over the last several years, a time when the industry has become more exposed to both natural gas and coal prices. This exposure was again highlighted in late 2005 when two major hurricanes severely disrupted natural gas production in the Gulf Coast region, leading to a sudden and sustained increase in natural gas prices. Such costs are for the most part out of the utility's control, although some try to manage them by hedging their fuel supply to some degree. However, both the magnitude and volatility of these costs make fuel adjustment clauses one of the more widely used and effective cost recovery mechanisms in the industry.

In some cases, fuel adjustment clauses may be limited in scope or subject to regulatory review to ensure that the costs that are incurred are prudent. Some states allow rate adjustments within certain ranges or bandwidths, with any costs incurred outside of these ranges deferred for recovery in subsequent base rate cases. Cost deferred and recovered through later base rate cases depress cash flow and inevitably add to regulatory lag, a short-term issue that should not negatively affect long-term credit quality

Fuel adjustment clauses, which also include purchased power costs, have also become critical to transmission and distribution utilities that no longer own generation assets following the deregulation of electricity markets in their states. Many of these companies are responsible for procuring power for their retail customers as part of their Provider of Last Resort or POLR obligations and, as a result, are responsible for procuring their generation requirements in the wholesale power markets. The lack of a prompt and timely generation cost adjustment clause or similar pass-through mechanism can have a detrimental effect on transmission and distribution utility cash flows and credit quality.

Automatic adjustment clauses and other pass-through mechanisms have been expanded over the years and now cover costs as diverse as transmission, new generation, renewable energy, environmental compliance costs, demand side management and energy efficiency costs, pensions, and bad debt expenses. These clauses may also be put in place for more unusual or extraordinary costs such as those incurred as a result of hurricanes or ice storms. In some states, changes in interest expense relative to what had been incorporated into existing rates have also been covered by such clauses. Like fuel and purchased power adjustment clauses, these other clauses are likely to increase the likelihood of timely recovery of prudently incurred costs, reduce regulatory uncertainty, and lead to a higher score for a utility's cost recovery factor in our ratings methodology.

Forecast Risk – Historical Versus Forward Test Years

In most utility ratemaking procedures, the selection of a test year is an important consideration in determining both the level of adjustments to rates that may be necessary later and the degree of regulatory lag the may result. A test year is the base year in which a forecast of a utility's operations and investment requirements over a twelve month period is devised. It is supposed to be representative of what costs will be incurred by a utility during an upcoming period, and establish what additional rate adjustments a utility will need to cover costs and earn an adequate rate of return. Depending on the regulatory provisions of a particular state, utilities are generally required to use either a historical test year or a future test year. In some cases, a combination or "hybrid" of these two test year periods can be used, with "known and measurable" adjustments.

A historical test year utilizes a twelve month period before the current rate filing as the basis for determining future rates. Some state regulatory commissions prefer historic tests years because the information used in determining rates is based on actual data that can be easily measured and analyzed.

However, in situations where industry conditions are changing rapidly, such as when costs are increasing or capital expenditures growing, historical test years are generally less useful as an accurate data point for setting future rates. In addition, the use of historical test years can contribute to regulatory lag in that a utility must usually file another rate case to recover those costs not accurately predicted with the use of the historical test year. As a result, utilities that use historical test years typically do not earn their allowed rate of return on an ongoing basis and experience persistent regulatory lag in the recovery of costs.

The use of a forward (or future) test year, while not a perfect predictor of future utility revenue requirements, strives to use the most timely and up-to-date information available in setting rates. Forward test years are typically based on forecasts of future costs and expenses, often leading to a high degree of scrutiny by regulators on the financial models and assumptions used in creating these forecasts. While all forecasts have limitations, forward test years are generally better predictors of future utility conditions than historical test years, especially where there are rapidly changing industry conditions. Forward test years can better incorporate current and expected economic conditions, a utility's capital expenditure budget going forward, and projected changes to a utility's customer base or load growth forecasts, for example. Moreover, forward test years help to reduce regulatory lag and ensure that a utility earns closer to its allowed rate of return. As a result, from a credit standpoint, Moody's views the use of forward test years as more supportive of utility credit quality than historical test years.

Regulatory Pre-Approvals

The utilities industry is in the midst of a substantial capital expenditure program, with significant investment planned in all aspects of its business, including generation, transmission, and distribution, as well as for substantial environmental compliance expenditures. Because of the size and complexity of many of these projects, Moody's places a high degree of emphasis on the regulatory certainty for the recovery of such costs, which is critical for the maintenance of utility credit quality. For some of these projects, especially when considering added uncertainty related to the economy and the timing of future laws and regulations related to carbon, it will be viewed as a significant credit positive if utilities are able to obtain regulatory support for recovery in advance. This would serve to limit regulatory risk associated with eventual disallowance or nonrecovery of already expended costs. Some U.S. states, including Idaho, Iowa, Virginia, and Wisconsin, have passed legislation pre-approving some generation costs and outlining cost recovery provisions for new plant construction, which Moody's considers to be a positive regulatory development for the utilities in those states. In India, the construction of Ultra Mega Power Projects do not have any cost recovery provisions, but are rather based on competitive tariff structures. Pre-approval of purchased power agreements would also be considered positively from a credit standpoint.

Approval of future project capital expenditures in advance requires a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service. In order for a state regulatory commission to pre-approve costs for a large and complex project, it is necessary for the commission and commission staff to gain an understanding of the project, including the need for the project, the construction budget, and the financing plan. Some projects underway right now, such as new nuclear construction, are expensive, complex, and multi-year in scope, and may not have been undertaken at all if regulators were not on board with the prudency of their projected costs and timetable in advance.

Regulatory pre-approval of utility capital expenditures may include incentives, mandated completion dates, or caps on the aggregate amount of recovery, giving state regulators some control over the ultimate costs and thus limiting ratepayer exposure in the event there are cost overruns or delays. In some cases, utilities may seek pre-approval for capital expenditures on a regular basis, such as annually or semi-annually, throughout the project's construction period. For example, for the recovery of costs related to Georgia Power's new nuclear construction project at its Vogtle plant site, the utility files a semi-annual construction monitoring report with the Georgia Public Service Commission (GPSC), with the GPSC reviewing and approving project costs on an ongoing basis. South Carolina Electric & Gas has a similar arrangement with the South Carolina Public Service Commission (SCPSC) for new nuclear construction at its Summer plant site. In order for such a pre-approval arrangement to be effective, however, state commissions need to have the time, ability, and resources to properly evaluate a complex project's construction progress, as well as any potential delays or problems that may arise. The Indiana Utility Regulatory Commission, for example, has an engineer advising them on Duke Indiana's Edwardsport project. Moody's views such collaborative utility-regulatory commission relationships as positive and important in insuring that prudent project costs are eventually recovered. They also serve to limit, but not fully protect against, the risk that there will be significant stranded, disallowed or otherwise unrecovered expenditures.

Construction Work in Progress (CWIP) in Rate Base/Concurrent Recovery

"Construction work in progress" (CWIP) represents the cost of capital projects that are under construction but not yet in service and considered "used-and-useful" in the provision of electric and/or gas service. Under traditional utility ratemaking, these costs cannot be included in customer rates until a project is completed and fully operational. However, because of the long lead times and large cost of many utility construction projects, some utilities are permitted by regulators to include CWIP in rate base, allowing it to earn a cash return on the project while it is under construction. The alternative would be for a utility to accumulate the financing costs on CWIP over the construction period (called "allowance for funds used during construction" or AFUDC) and include them in rates when the project is completed. Proponents of this approach generally argue that it is appropriate for utility ratepayers to pay only for projects that are in use and currently benefiting them through the provision of electricity and/or gas.

Moody's views the inclusion of CWIP in rate base as supportive of utility credit quality. It helps moderate the financial pressure of the incremental construction related debt by providing a cash return during lengthy, sometimes uncertain, and potentially delayed construction periods. It also allows a project's costs to be gradually incorporated into rates rather than all at once at the conclusion of construction, when a large and potentially unpopular one-time rate increase may be required. The resulting rate shock could lead to further delays in the recovery of these costs or political/legislative intervention aimed at limiting or denying utility cost recovery altogether.

It should be noted that not all CWIP recovery provisions are the same. Some state regulatory commissions only allow a portion of CWIP to be included in rate base, some only allow a debt return, while others allow a full weighted average cost of capital return. From a credit perspective, inclusion of all CWIP in rate base at a full weighted average cost of capital return would be considered the most supportive CWIP recovery provision.

Whether to allow CWIP in rate base became a significant issue several years ago, particularly during the last round of nuclear construction in the 1970's, when a number of utilities were engaged in major nuclear construction projects and substantial cost overruns were commonplace. This was also an era of high inflation and high interest rates, exacerbating the rate impact of allowing CWIP in rate base. Because of this experience, a few states actually passed laws prohibiting utilities from including CWIP in rate base, some of which are still on the books today. The issue has again come to the forefront with the advent of major new nuclear construction in the U.S., and also because of large capital expenditure plans for transmission, renewable energy projects, integrated gasification combined-cycle (IGCC) plants, and environmental compliance requirements. Although the treatment of CWIP by individual state regulatory commissions varies, most states do allow for the inclusion of some or all of CWIP in rate base, a credit positive. Those states that do not allow the inclusion of CWIP in rate base, either by law or by recent commission decision, are listed below.

TABLE 2

States Not Allowing CWIP in Rate Base

LEGALLY PROHIBITED	DENIED BY COMMISSION
Connecticut	Arizona
Missouri	Nebraska
New Hampshire	Oklahoma
Oregon	Rhode Island
Pennsylvania	

The inclusion of CWIP in rate base is an especially important credit supportive measure for those utilities in the process of constructing new nuclear plants. In Georgia and Florida, for example, legislation passed over the last few years allows utilities in both states to earn a cash return on CWIP for new nuclear construction. For Georgia Power, the inclusion of CWIP in rate base and the recovery of financing costs on its new Vogtle nuclear construction project reduced the project's in-service cost to $4.5 billion from $6.4 billion. Similarly, in South Carolina, the Public Service Commission has authorized South Carolina Electric & Gas to earn a cash return on CWIP associated with new nuclear construction in that state. In contrast, in early 2009, Ameren subsidiary AmerenUE suspended efforts to build a new nuclear plant in Missouri after legislation allowing CWIP in rate base was not passed by the Missouri General Assembly.

As previously mentioned, the less favorable alternative to inclusion of CWIP in rate base from a credit standpoint is allowance for funds used during construction (AFUDC) accounting treatment for construction projects. With AFUDC, capital projects do not earn a cash return during the construction phase, but do when they become used and useful. Because of the long lead times and large cost of many utility construction projects, this can place great financial and liquidity pressure on utilities. Under AFUDC accounting conventions, a utility's earnings are made whole by non-cash earnings, offsetting the incremental debt and equity capital costs incurred to finance the projects. While there is no earnings impact on a utility income statement, cash flow generally lags while debt mounts, a credit negative. Some opponents to AFUDC treatment argue that rate payers generally face a larger one-time rate increase under this approach than if CWIP treatment was applied.

Interim Rate Relief

Because of the length of base rate cases, with many lasting 12 months and some as long as 18 months, interim rate relief is often an effective way to accelerate rate relief, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. While some states allow utilities to petition for interim rate relief, others only permit such relief in extraordinary or emergency situations, limiting its use to unusually dire circumstances. Interim rate relief is also difficult for state regulators to grant when there are poor economic conditions in a utility's service territory, and some requests for interim rate relief are declined for these reasons. Because interim rate relief has a positive impact on utility cash flows and coverage metrics and reduces regulatory lag, Moody's views interim rate relief as a positive credit consideration. The existence of a maximum timeframe for decisions on interim (or general) rate cases is another important credit consideration. If there is no statutory time limit for rendering such rate case decisions, regulatory lag can result.

In Florida, utilities may request an interim rate increase only if they have petitioned the Florida Public Service Commission (FPSC) for a permanent base rate increase. In its most recent rate case, for example, Progress Energy Florida requested and was granted an interim rate increase to recover the costs of repowering one of its generating units to natural gas from oil. The interim rates were put in effect during the course of the base rate proceeding, which in Florida takes about nine months. Interim rates are credited back to customers, with interest, if the FPSC determines in its final rate decision that the interim rates were not justified. In Hawaii, interim rates must be enacted within 11 months of filing, but there is no statutory time limit for a final decision. As such, the majority of Hawaiian Electric rate decisions in recent years have been interim decisions.

In West Virginia, Appalachian Power and Wheeling Power, both subsidiaries of American Electric Power (AEP), requested an interim rate increase of $180 million in April 2009, out of an overall $442 million rate increase request, for fuel, purchased power, and environmental compliance project expenses. Because of sharply higher fuel costs, the company was paying more for fuel than it was receiving in existing rates and hoped the interim rates would offset a growing fuel underrecovery. On June 4, 2009, the Public Service Commission of West Virginia denied the request, citing the potential for financial hardship on customers, especially during currently difficult economic times. The denial of interim rate relief is considered a credit negative in that it added to fuel underrecoveries and increased regulatory lag at the utilities.

Volume Risk and Decoupling

There has been a great deal of emphasis and attention in recent years given to energy efficiency and demand side management programs aimed at reducing the consumption of electricity and natural gas both because of environmental concerns and for economic reasons. For utilities these efforts represent a potential threat to cost recovery because under traditional rate of return regulation, utility revenues are a function of the volume of power and energy is sold, i.e. all or a portion of the utility's fixed costs are recovered through volumetric charges. Consequently, utilities that are dependent on volume are, in fact, economically motivated to encourage higher energy usage instead of conservation and energy efficiency. Decoupling is aimed at "de-linking" a utility's revenues and profits from volume and at the same time compensating utilities for promoting less energy use.

Decoupling has become more prevalent over the last year since the Federal government's economic stimulus bill was passed in February 2009. That bill provides significant funding to states to promote and encourage energy efficiency programs, but only in the event there are incentives in place for utilities themselves to encourage and promote such programs. There are still relatively few states with decoupling measures in place for electric utilities, although they have been more common for gas utilities. Moody's views decoupling measures as important to the maintenance of utility credit quality in states where energy efficiency and demand side management programs could put pressure on utility sales volumes, operating margins, and cash flow coverage metrics.

TABLE 3

Selected States With Decoupling Measures in Place

ELECTRIC DECOUPLING	GAS DECOUPLING
California	Arkansas
Connecticut	California
Idaho	Colorado
Maryland	Illinois
Massachusetts	Indiana
Michigan	Maryland
New Hampshire	Massachusetts
New York	Michigan
Oregon	Minnesota
Vermont	New Jersey
	New York
	Nevada
	North Carolina
	Ohio
	Oregon
	Utah
	Virginia
	Washington
	Wisconsin
	Wyoming

The state of California was at the forefront of states adopting decoupling as far back as 1982, when it put an Electric Revenue Adjustment Mechanism in place, which de-linked utility revenues from utility sales to promote energy conservation. Other states have introduced decoupling more recently, including Idaho, Maryland, Massachusetts, and New York. Some states have partial decoupling measures in place, such as New Hampshire, which allows decoupling for generation and transmission, but not for distribution. Hawaii has recently approved a decoupling mechanism, which is most similar to the California model, but it has yet to be fully implemented into electric rates. Many more states are considering decoupling measures and Moody's expects such measures to become increasingly prevalent as energy efficiency and demand side management programs are increasingly emphasized.

Cost Recovery Bonds (Securitization)

Since the late 1990's, legislatively approved stranded cost, storm cost, and other cost recovery bonds have been issued to reimburse utilities for costs related to deregulation, hurricanes, environmental compliance, and energy supply. In its simplest form, a securitization is a type of irrevocable rate order that authorizes and dedicates a stream of cash flow to service bonds issued to reimburse utilities for specific costs. Such bonds were originally issued to compensate utilities for stranded costs following the deregulation of the energy markets in some states several years ago. More recently, storm-related securitizations have been completed following active hurricane seasons in 2004, 2005 and 2008 along the Gulf Coast region and in Florida. Securitization bonds have also been issued to finance environmental compliance costs in West Virginia.

Cost recovery bonds represent another way that regulatory commissions and state legislatures can assure that a utility receives adequate recovery for sometimes large and unanticipated capital expenditures, while avoiding the rate shock that could result from passing through all these costs over a limited time frame. Instead, cost recovery bonds allow these costs to be spread out and financed over a multi-year period. Customers benefit from the low financing costs that characterize such bonds, since the special purpose entities issuing the bonds are typically rated Aaa, and the utility is reimbursed for the costs it incurred fairly quickly when the bonds are issued, reducing regulatory lag. However, Moody's notes that some storm cost recovery bonds have been issued as long as two to three years after the costs have been incurred, in some cases due to the need to pass legislation authorizing such bonds. Such legislation is necessary to insure that the collection of the cost recovery bond surcharge is statutorily protected, irrevocable, and non-bypassable. Moody's views utilities that have the option of issuing cost recovery bonds in the event of large, unexpected, or extraordinary costs more favorably from a credit point of view.

Conclusion

Cost recovery provisions and a utility's ability to earn an adequate return are important considerations in determining credit quality and credit ratings in the regulated utility sector, so much so that they account for a significant 25% weighting when determining utility credit ratings under our Rating Methodology. Among the provisions we consider when judging this factor include a utility's ability to earn its allowed return on equity, which must be examined in conjunction with its actual earned return on equity resulting from its overall cost recovery provisions. These provisions could include automatic adjustment clauses, the use of a forward test year, regulatory pre-approval of major capital expenditures, construction work in progress (CWIP) in rate base, interim rate relief, decoupling, and the option of issuing cost recovery or securitized bonds to recovery large or unexpected costs. The presence of most or all of these provisions is likely to lead to a higher score for the cost recovery and earned return factor in our ratings methodology.

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Appendix A: Current Factor 2 Scoring for the operating utilities in Moody's rated universe

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
Tennessee Valley Authority	Chubu Electric Power Company, Incorp.	Alabama Power Company	ALLETE, Inc.	Companhia Energetica de Minas Gerais - CEMIG	Perusahaan Listrik Negara (P.T.)
	Chugoku Electric Power Company, Incorp.	Consumers Energy Company	Appalachian Power Company	Cemig Geracao e Transmissao S.A.	
	CLP Power Hong Kong Limited	Dayton Power & Light Company	Arizona Public Service Company	Companhia Paranaense de Energia - COPEL	
	Electric Power Delevopment Co., Ltd.	Detroit Edison Company (The)	Black Hills Power, Inc.	EDP – Energias do Brasil	
	Hokkaido Electric Power Company, Incorp.	Duke Energy Carolinas, LLC	Central Vermont Public Service Corp.	Empresas Publicas de Medelin E.S.P.	
	Hokuriku Electric Power Company	Duke Energy Indiana, Inc.	Cleco Power LLC	Entergy Texas	
	Kansai Electric Power Company, Incorp.	Florida Power & Light Company	Columbus Southern Power Company	Eskom Holdings Ltd	
	Kyushu Electric Power Company, Incorp.	FortisBC Inc	Duke Energy Kentucky, Inc.	Furnas Centrais Electricas S.A.	
	Okinawa Electric Power Company, Incorp.	Georgia Power Company	Duke Energy Ohio, Inc.	Israel Electric Corporation Limited (The)	
	Osaka Gas Co., Ltd.	Gulf Power Company	EDA - Electricidade dos Acores, S.A.	Light S.A.	
	Tokyo Electric Power Company, Incorp.	Indianapolis Power & Light Company	Eesti Energia AS	NTPC Limited	
	Tokyo Gas Co., Ltd.	Interstate Power & Light Company	El Paso Electric Company	Tata Power Company Limited (The)	
		Kentucky Utilities Co.	Empire District Electric Company (The)	Union Electric Company	
		Louisville Gas & Electric Company	Empresa de Electricidade da Madeira, S.A.		
		Madison Gas and Electric Company	Entergy Arkansas, Inc.		
		MidAmerican Energy Company	Entergy Gulf States Louisiana, LLC		
		Mississippi Power Company	Entergy Louisiana, LLC		
		Northern Indiana Public Service	Entergy Mississippi, Inc.		
		Northern States Power Company (Minnesota)	Entergy New Orleans, Inc.		
		Northern States Power Company (Wisconsin)	Hawaiian Electric Company, Inc.		
		Oklahoma Gas & Electric Company	Hydro-Québec		
		Pacific Gas & Electric Company	Idaho Power Company		
		Progress Energy Carolinas, Inc.	Indiana Michigan Power Company		
		Progress Energy Florida, Inc.	Kansas City Power & Light Company		
		Public Service Company of Colorado	Kentucky Power Company		
		South Carolina Electric & Gas Company	Korea Electric Power Corporation		
		Southern California Edison Company	Latvenergo		
		Southern Indiana Gas & Electric	Monongahela Power Company		
		Superior Water, Light and Power Company	Nevada Power Company		

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
		Tampa Electric Company	NorthWestern Corporation		
		Virginia Electric and Power Company	Ohio Power Company		
		Wisconsin Electric Power Company	Otter Tail Corporation		
		Wisconsin Power and Light Company	PacifiCorp		
		Wisconsin Public Service Corporation	Portland General Electric Company		
			Public Service Company of New Hampshire		
			Public Service Company of New Mexico		
			Public Service Company of Oklahoma		
			Puget Sound Energy, Inc.		
			Sierra Pacific Power Company		
			Southwestern Electric Power Company		
			Southwestern Public Service Company		
			Taiwan Power Company Limited		
			Tenaga Nasional Berhad		
			Tucson Electric Power Company		
			UNS Electric		

T&D Utilities

Aa	A	Baa	Ba	B
Hong Kong and China Gas Co. Ltd	AEP Texas Central Company	Atlantic City Electric Company	AES Eletropaulo	Edenor S.A.
Oman Power and Water Procur. Co.	AEP Texas North Company	Baltimore Gas and Electric Company	AES El Salvado Trust	
	CenterPoint Energy Houston Electric, LLC	Central Illinois Light Company	Bandeirante Energia S.A.	
	Central Hudson Gas & Electric Corporation	Central Illinois Public Service Company	Cemig Distribuicao S.A.	
	Central Maine Power Company	Cleveland Electric Illuminating Company (The)	Centrais Eletricas do Para S.A.	
	Consolidated Edison Company of New York, Inc.	Commonwealth Edison Company	Centrais Eletricas Matogrossenses S.A.	
	FortisAlberta Inc.	Connecticut Light and Power Company	Comp. de Ener. Eletr. do Est. do Tocantins	
	Hydro One Inc.	Delmarva Power & Light Company	Espirito Santo Centrais Eletricas - ESCELSA	
	Massachusetts Electric Company	Duquesne Light Company	Ejesa S.A.	
	New England Power Company	Illinois Power Company	Empresa Electrica de Guatemala, S.A.	
	Newfoundland Power Inc.	Jersey Central Power & Light Company	Energisa Paraiba-Dist. de Energia S.A.	
	Niagara Mohawk Power Corporation	Metropolitan Edison Company	Energisa Sergipe - Dist. de Energia S.A.	
	NSTAR Electric Company	Narragansett Electric Company	Gas Authority Inida Limited	
	Oncor Electric Delivery Company	New York State Electric and Gas Corporation	Light Serviços de Eletricidade S.A.	
	Orange and Rockland Utilities, Inc.	Ohio Edison Company	Perusahaan Gas Negara	
	Public Service Electric and Gas Company	PECO Energy Company	Rede Energia	
	San Diego Gas & Electric Company	Pennsylvania Electric Company	Rio Grande Energia S.A. - RGE	
		Pennsylvania Power Company	Towngas China Co. Ltd	
		Potomac Edison Company (The)	Xinao Gas Holdings Ltd	
		Potomac Electric Power Company		
		PPL Electric Utilities Corporation		
		Rochester Gas & Electric Corporation		
		Texas-New Mexico Power Company		
		Toledo Edison Company		
		United Illuminating Company		
		West Penn Power Company		
		Western Massachusetts Electric Company		

Transmission Only Utilities

A
American Transmission Company LLC
American Transmission Systems
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company
Trans-Allegheny Interstate Line Company

Local Gas Distribution Companies (LDCs)

Aa	A	Baa	Ba	B
Terasen Gas (Vancouver Island) Inc.	Atlanta Gas Light Company	Berkshire Gas Company	Gas Natural Ban S.A.	Camuzzi Gas Pampeana S.A.
	Bay State Gas Company	Boston Gas Company		Metrogas S.A.
	Brooklyn Union Gas Company, The	Cascade Natural Gas Corp.		
	Indiana Gas Company, Inc.	Cia de Gas de São Paulo - COMGAS		
	Michigan Consolidated Gas Company	Colonial Gas Company		
	New Jersey Natural Gas Company	Connecticut Natural Gas Corporation		
	Northwest Natural Gas Company	Laclede Gas Company		
	Piedmont Natural Gas Company, In	North Shore Gas Company		
	Public Service Co. of North Carolina, Inc.	Northern Illinois Gas Company		
	South Jersey Gas Company	Peoples Gas Light and Coke Co.		
	Southern California Gas Company	SEMCO Energy, Inc.		
	Terasen Gas Inc.	Source Gas LLC		
	Wisconsin Gas LLC	Southern Connecticut Gas Company		
		Southwest Gas Corporation		
		UGI Utilities, Inc.		
		UNS Gas		
		Washington Gas Light Company		
		Yankee Gas Services Company		

Moody's Related Research

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Industry Outlook:

» U.S. Electric Utilities Face Challenges Beyond Near-Term, January 2010 (121717)

Special Comment:

» Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, June 2010 (125664)

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» contacts continued from page 1

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2014 Classic Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2013

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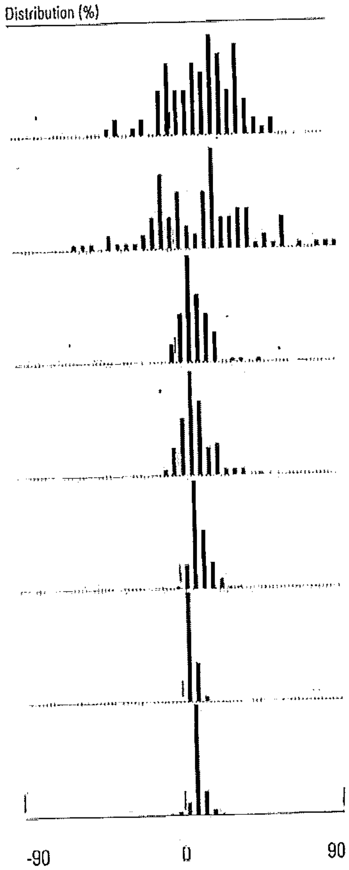
Table 2-1: Basic Series: Summary Statistics of Annual Total Returns

Series	Geometric Mean (%)	Arithmetic Mean (%)	Standard Deviation (%)
Large Company Stocks	10.1	12.1	20.2
Small Company Stocks*	12.3	16.9	32.3
Long-Term Corporate Bonds	6.0	6.3	8.4
Long-Term Government Bonds	5.5	5.9	9.8
Intermediate-Term Government Bonds	5.3	5.4	5.7
U.S. Treasury Bills	3.5	3.5	3.1
Inflation	3.0	3.0	4.1



Data from 1926–2013. * The 1933 Small Company Stocks Total Return was 142.9 percent.

Note that in Table 2-1, the arithmetic mean returns are always higher than the geometric mean returns. The difference between these two means is related to the standard deviation, or variability, of the series. [See Chapter 6.]

The "skylines" or histograms in Table 2-1 show the frequency distribution of returns on each asset class. The height of the common stock skyline in the range between +10 and +20 percent, for example, shows the number of years in 1926–2013 that large company stocks had a return in that range. The histograms are shown in 5 percent increments to fully display the spectrum of returns as seen over the last 88 years, especially in stocks.

Riskier assets, such as large company stocks and small company stocks, have low, spread-out skylines, reflecting the broad distribution of returns from very poor to very good. Less risky assets, such as bonds, have narrow skylines that resemble a single tall building, indicating the tightness of the distribution around the mean of the series. The histogram for Treasury bills is one-sided, lying almost entirely to the right of the vertical line representing a zero return; that is, Treasury bills rarely experienced negative returns on a yearly basis over the 1926–2013 period. The inflation skyline shows both positive and negative annual rates. Although a few deflationary months and quarters have occurred recently, the last negative annual inflation rate occurred in 1954.

Capital Appreciation, Income, and Reinvestment Returns

Table 2-2 provides further detail on the returns of large company stocks, long-term government bonds, and intermediate-term government bonds. Total annual returns are shown as the sum of three components: capital appreciation returns, income returns, and reinvestment returns. The capital appreciation and income components are explained in Chapter 3. The third component, reinvestment return, reflects monthly income reinvested in the total return index in subsequent months in the year. Thus, for a single month the reinvestment return is zero, but over a longer period of time it is non-zero. Since the returns in Table 2-2 are annual, reinvestment return is relevant.

The annual total return formed by compounding the monthly total returns does not equal the sum of the annual capital appreciation and income components; the difference is reinvestment return. A simple example illustrates this point. In 1995, an "up" year on a total return basis, the total annual return on large company stocks was 37.58 percent. The annual capital appreciation was 34.11 percent and the annual income return was 3.04 percent, totaling 37.15 percent. The remaining 0.43 percent (37.58 percent minus 37.15 percent) of the 1995 total return came from the reinvestment of dividends in the market. For more information on calculating annual total and income returns, see Chapter 5.

Monthly income and capital appreciation returns for large company stocks are presented in Appendix A: Tables A-2 and A-3, respectively. Monthly income and capital appreciation returns are presented for long-term government

Table 2-2: Large Company Stocks, Long-Term Government Bonds, and Intermediate-Term Government Bonds
Annual Total, Income, Capital Appreciation, and Reinvestment Returns (%)

	Large Company Stocks				Long-Term Government Bonds					Intermediate-Term Government Bonds				
Year	Capital Apprec Return	Income Return	Reinvest-ment Return	Total Return	Capital Apprec. Return	Income Return	Reinvest-ment Return	Total Return	Year-end Yield	Capital Apprec Return	Income Return	Reinvest-ment Return	Total Return	Year-end Yield
1926	5.72	5.41	0.50	11.62	3.91	3.73	0.13	7.77	3.54	1.51	3.78	0.10	5.38	3.61
1927	30.91	5.71	0.87	37.49	5.40	3.41	0.12	8.93	3.17	0.96	3.49	0.07	4.52	3.40
1928	37.88	4.81	0.91	43.61	-3.12	3.22	0.01	0.10	3.40	-2.73	3.64	0.01	0.92	4.01
1929	-11.91	3.98	-0.49	-8.42	-0.20	3.47	0.15	3.42	3.40	1.77	4.07	0.18	6.01	3.62
1930	-28.48	4.57	-0.98	-24.90	1.28	3.32	0.05	4.66	3.30	3.30	3.30	0.11	6.72	2.91
1931	-47.07	5.35	-1.62	-43.34	-8.46	3.33	-0.17	-5.31	4.07	-5.40	3.16	-0.08	-2.32	4.12
1932	-15.15	6.16	0.80	-8.19	12.94	3.69	0.22	16.84	3.15	5.02	3.63	0.16	8.81	3.04
1933	46.59	6.39	1.01	53.99	-3.14	3.12	-0.05	-0.07	3.36	-0.99	2.83	-0.02	1.83	3.25
1934	-5.94	4.46	0.04	-1.44	6.76	3.18	0.09	10.03	2.93	5.97	2.93	0.09	9.00	2.49
1935	41.37	4.95	1.35	47.67	2.14	2.81	0.03	4.98	2.76	4.94	2.02	0.05	7.01	1.63
1936	27.92	5.36	0.64	33.92	4.64	2.77	0.10	7.52	2.55	1.60	1.44	0.02	3.06	1.29
1937	-38.59	4.66	-1.09	-35.03	-2.48	2.66	0.05	0.23	2.73	0.05	1.48	0.03	1.56	1.14
1938	25.21	4.83	1.07	31.12	2.83	2.64	0.06	5.53	2.52	4.37	1.82	0.04	6.23	1.52
1939	-5.45	4.69	0.35	-0.41	3.48	2.40	0.06	5.94	2.26	3.18	1.31	0.03	4.52	0.98
1940	-15.29	5.36	0.14	-9.78	3.77	2.23	0.09	6.09	1.94	2.04	0.90	0.02	2.96	0.57
1941	-17.86	6.71	-0.44	-11.59	-1.01	1.94	0.00	0.93	2.04	-0.17	0.67	0.00	0.50	0.82
1942	12.43	6.79	1.12	20.34	0.74	2.46	0.02	3.22	2.46	1.17	0.76	0.00	1.94	0.72
1943	19.45	6.24	0.21	25.90	-0.37	2.44	0.02	2.08	2.48	1.23	1.56	0.02	2.81	1.45
1944	13.80	5.48	0.47	19.75	0.32	2.46	0.03	2.81	2.46	0.35	1.44	0.01	1.80	1.40
1945	30.72	4.97	0.74	36.44	8.27	2.34	0.12	10.73	1.99	1.02	1.19	0.01	2.22	1.03
1946	-11.87	4.09	-0.20	-8.07	-2.15	2.04	0.01	-0.10	2.12	-0.08	1.08	0.00	1.00	1.12
1947	0.00	5.49	0.22	5.71	-4.70	2.13	-0.06	-2.62	2.43	-0.30	1.21	0.00	0.91	1.34
1948	-0.65	6.08	0.08	5.50	0.96	2.40	0.04	3.40	2.37	0.27	1.56	0.01	1.85	1.51
1949	10.26	7.50	1.03	18.79	4.15	2.25	0.06	6.45	2.09	0.95	1.36	0.01	2.32	1.23
1950	21.78	8.77	1.16	31.71	-2.06	2.12	0.00	0.06	2.24	-0.69	1.39	0.00	0.70	1.62
1951	16.46	6.91	0.65	24.02	-6.27	2.38	-0.04	-3.93	2.69	-1.63	1.98	0.01	0.36	2.17
1952	11.78	5.93	0.66	18.37	-1.48	2.68	-0.02	1.16	2.79	-0.57	2.19	0.01	1.63	2.35
1953	-6.62	5.46	0.18	-0.99	0.67	2.84	0.12	3.64	2.74	0.61	2.55	0.07	3.23	2.18
1954	45.02	6.21	1.39	52.62	4.35	2.79	0.05	7.19	2.72	1.08	1.60	0.01	2.68	1.72
1955	26.40	4.56	0.60	31.56	-4.07	2.75	0.03	-1.29	2.95	-3.10	2.45	0.00	-0.65	2.80
1956	2.62	3.83	0.11	6.56	-8.46	2.99	-0.12	-5.59	3.45	-3.45	3.05	-0.02	-0.42	3.63
1957	-14.31	3.84	-0.30	-10.78	3.82	3.44	0.20	7.46	3.23	4.05	3.59	0.20	7.84	2.84
1958	38.06	4.38	0.93	43.36	-9.23	3.27	-0.14	-6.09	3.82	-4.17	2.93	-0.05	-1.29	3.81
1959	8.48	3.31	0.16	11.96	-6.20	4.01	-0.07	-2.26	4.47	-4.56	4.18	-0.01	-0.39	4.98
1960	-2.97	3.26	0.19	0.47	9.29	4.26	0.23	13.78	3.80	7.42	4.15	0.19	11.76	3.31
1961	23.13	3.48	0.28	26.89	-2.86	3.83	0.00	0.97	4.15	-1.72	3.54	0.03	1.85	3.84
1962	-11.81	2.98	0.10	-8.73	2.78	4.00	0.11	6.89	3.95	1.73	3.73	0.10	5.56	3.50
1963	18.89	3.61	0.30	22.80	-2.70	3.89	0.02	1.21	4.17	-2.10	3.71	0.03	1.64	4.04
1964	12.97	3.33	0.18	16.48	-0.72	4.15	0.07	3.51	4.23	-0.03	4.00	0.07	4.04	4.03
1965	9.06	3.21	0.18	12.45	-3.45	4.19	-0.04	0.71	4.50	-3.10	4.15	-0.03	1.02	4.90
1966	-13.09	3.11	-0.08	-10.06	-1.06	4.49	0.22	3.65	4.55	-0.41	4.93	0.17	4.69	4.79
1967	20.09	3.64	0.25	23.98	-13.55	4.59	-0.23	-9.18	5.56	-3.85	4.88	-0.02	1.01	5.77
1968	7.66	3.18	0.22	11.06	-5.51	5.50	-0.25	-0.26	5.98	-0.99	5.49	0.03	4.54	5.96
1969	-11.36	2.98	-0.13	-8.50	-10.83	5.95	-0.19	-5.07	6.87	-7.27	6.65	-0.11	-0.74	8.29
1970	0.10	3.33	0.43	3.86	4.84	6.74	0.52	12.11	6.48	8.71	7.49	0.66	16.86	5.90

Table 2-2: Large Company Stocks, Long-Term Government Bonds, and Intermediate-Term Government Bonds (Continued)
Annual Total, Income, Capital Appreciation, and Reinvestment Returns (%)

	Large Company Stocks				Long-Term Government Bonds					Intermediate-Term Government Bonds				
Year	Capital Apprec. Return	Income Return	Reinvest-ment Return	Total Return	Capital Apprec. Return	Income Return	Reinvest-ment Return	Total Return	Year-end Yield	Capital Apprec. Return	Income Return	Reinvest-ment Return	Total Return	Year-end Yield
1971	10.63	3.49	0.18	14.30	6.61	6.32	0.31	13.23	5.97	2.72	5.75	0.25	8.72	5.25
1972	15.79	2.95	0.25	18.99	-0.35	5.87	0.17	5.69	5.99	-0.75	5.75	0.16	5.16	5.85
1973	-17.37	2.86	-0.19	-14.69	-7.70	6.51	0.08	-1.11	7.26	-2.19	6.58	0.22	4.61	6.79
1974	-29.72	3.69	-0.44	-26.47	-3.45	7.27	0.54	4.35	7.60	-1.99	7.24	0.44	5.69	7.12
1975	31.55	5.37	0.31	37.23	0.73	7.99	0.47	9.20	8.05	0.12	7.35	0.36	7.83	7.19
1976	19.15	4.49	0.29	23.93	8.07	7.89	0.80	16.75	7.21	5.25	7.10	0.51	12.87	6.00
1977	-11.50	4.35	0.00	-7.16	-7.86	7.14	0.04	-0.69	8.03	-5.15	6.49	0.06	1.41	7.51
1978	1.06	5.33	0.18	6.57	-9.05	7.90	-0.03	-1.18	8.98	-4.49	7.83	0.14	3.49	8.83
1979	12.31	5.89	0.41	18.61	-9.84	8.86	-0.25	-1.23	10.12	-5.07	9.04	0.12	4.09	10.33
1980	25.77	5.74	0.99	32.50	-14.00	9.97	0.08	-3.95	11.99	-6.81	10.55	0.17	3.91	12.45
1981	-9.73	4.88	-0.08	-4.92	-10.33	11.55	0.64	1.86	13.34	-4.55	12.97	1.03	9.45	13.96
1982	14.76	5.61	1.18	21.55	23.95	13.50	2.91	40.36	10.95	14.23	12.81	2.06	29.10	9.90
1983	17.27	5.04	0.24	22.56	-9.82	10.38	0.09	0.65	11.97	-3.30	10.35	0.35	7.41	11.41
1984	1.40	4.57	0.31	6.27	2.32	11.74	1.42	15.48	11.70	1.22	11.68	1.12	14.02	11.04
1985	26.33	4.72	0.67	31.73	17.84	11.25	1.88	30.97	9.56	9.01	10.29	1.04	20.33	8.55
1986	14.62	3.92	0.13	18.67	14.99	8.98	0.56	24.53	7.89	6.99	7.72	0.43	15.14	6.85
1987	2.03	3.64	-0.41	5.25	-10.69	7.92	0.06	-2.71	9.20	-4.75	7.47	0.19	2.90	8.32
1988	12.40	3.99	0.22	16.61	0.36	8.97	0.34	9.67	9.19	-2.26	8.24	0.13	6.10	9.17
1989	27.25	4.03	0.40	31.69	8.62	8.81	0.68	18.11	8.16	4.34	8.46	0.49	13.29	7.94
1990	-6.56	3.43	0.03	-3.10	-2.61	8.19	0.61	6.18	8.44	1.02	8.15	0.56	9.73	7.70
1991	26.31	3.76	0.40	30.47	10.10	8.22	0.98	19.30	7.30	7.36	7.43	0.67	15.46	5.97
1992	4.46	2.98	0.17	7.62	0.34	7.26	0.45	8.05	7.26	0.64	6.27	0.28	7.19	6.11
1993	7.06	2.91	0.12	10.08	10.71	7.17	0.35	18.24	6.54	5.56	5.53	0.15	11.24	5.22
1994	-1.54	2.83	0.03	1.32	-14.29	6.59	-0.08	-7.77	7.99	-11.14	6.07	-0.08	-5.14	7.80
1995	34.11	3.04	0.43	37.58	23.04	7.60	1.03	31.67	6.03	9.66	6.69	0.45	16.80	5.38
1996	20.26	2.43	0.26	22.96	-7.37	6.18	0.26	-0.93	6.73	-3.90	5.82	0.18	2.10	6.16
1997	31.01	2.10	0.25	33.36	8.51	6.64	0.71	15.85	6.02	1.95	6.14	0.30	8.38	5.73
1998	26.67	1.67	0.24	28.58	6.89	5.83	0.34	13.06	5.42	4.66	5.29	0.25	10.21	4.68
1999	19.53	1.36	0.15	21.04	-14.35	5.57	-0.19	-8.96	6.82	-7.06	5.30	-0.01	-1.77	6.45
2000	-10.14	1.11	-0.07	-9.10	14.36	6.50	0.62	21.48	5.58	5.94	6.19	0.46	12.59	5.07
2001	-13.04	1.18	-0.03	-11.89	-1.89	5.53	0.06	3.70	5.75	3.23	4.27	0.12	7.62	4.42
2002	-23.37	1.39	-0.13	-22.10	11.69	5.59	0.56	17.84	4.84	8.65	3.98	0.30	12.93	2.61
2003	26.38	1.99	0.31	28.68	-3.36	4.80	0.01	1.45	5.11	-0.48	2.85	0.03	2.40	2.97
2004	8.99	1.76	0.13	10.88	3.26	5.02	0.23	8.51	4.84	-1.07	3.28	0.04	2.25	3.47
2005	3.00	1.84	0.07	4.91	3.02	4.69	0.10	7.81	4.61	-2.58	3.92	0.03	1.36	4.34
2006	13.62	2.01	0.17	15.79	-3.64	4.68	0.15	1.19	4.91	-1.51	4.54	0.11	3.14	4.65
2007	3.53	1.96	0.00	5.49	4.69	4.86	0.33	9.88	4.50	5.33	4.44	0.28	10.05	3.28
2008	-38.49	1.92	-0.43	-37.00	20.50	4.45	0.93	25.87	3.03	9.92	2.96	0.23	13.11	1.26
2009	23.45	2.48	0.53	26.46	-18.25	3.47	-0.12	-14.90	4.58	-4.42	2.01	0.00	-2.40	2.42
2010	12.78	2.02	0.26	15.06	5.89	4.25	0.00	10.14	4.14	5.16	1.92	0.04	7.12	1.70
2011	0.00	2.13	-0.01	2.11	23.74	3.81	0.68	28.23	2.48	7.79	1.58	0.09	9.46	0.59
2012	13.41	2.50	0.10	16.00	0.88	2.40	0.02	3.31	2.41	1.48	0.58	0.01	2.07	0.46
2013	29.60	2.48	0.32	32.39	-14.83	2.86	0.61	-11.36	3.67	-1.91	0.85	0.00	-1.07	1.13

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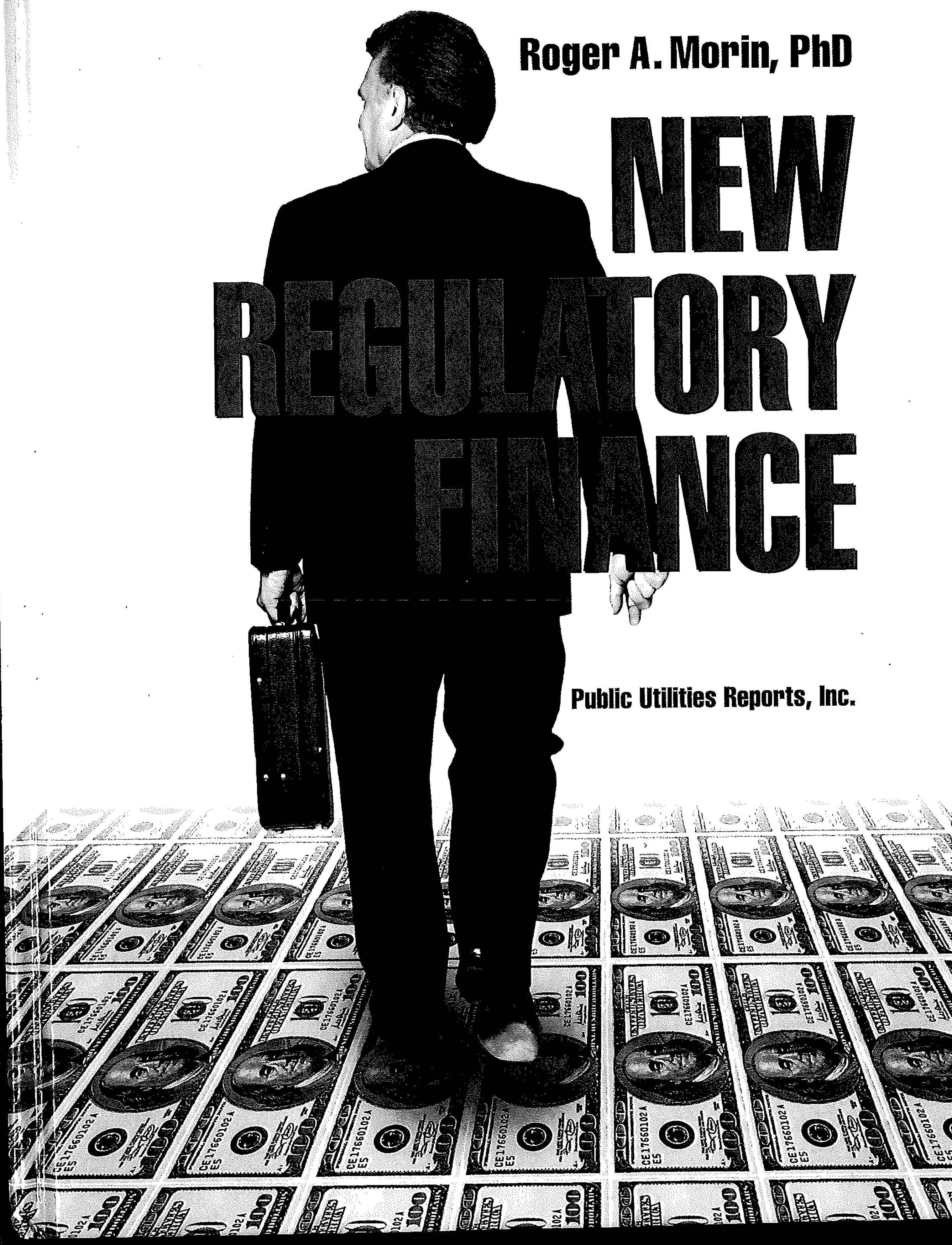
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historical risk premium approach assumes that the average realized return is an appropriate surrogate for expected return, or, in other words, that investor expectations are realized. However, realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods.

The prospective (forecast) approach examines the returns expected from investments in common equities and bonds. The risk premium is simply the difference between the expected returns on stocks and bonds. The prospective approach is subject to the inevitable measurement errors involved in computing expected returns.

Therefore, a regulatory body should rely on the results of both historical and prospective studies in arriving at an appropriate risk premium, data permitting. Each proxy for the expected risk premium brings information to the judgment process from a different light. Neither proxy is without blemish, each has advantages and shortcomings. Historical risk premium data are available and verifiable, but may no longer be applicable if structural shifts have occurred. Prospective risk premium data may be more relevant since they encompass both history and current changes, but are nevertheless imperfect proxies. Giving equal weight to the historical risk premium and the prospective risk premium forecast represents a compromise between the certainty of the past and its possible irrelevance versus the greater relevance of the forecast and its possible estimation error.[13]

Faced with this myriad, and often conflicting, evidence on the magnitude of the risk premium, a regulator might very well be confused about the correct market risk premium. The author's opinion is that a range of 5% to 8% is reasonable for the United States with a slight preference for the upper end of the range.

As in the case of the beta estimate and risk-free rate estimate, a sensitivity analysis of possible CAPM cost of capital estimates should be conducted for a specified utility using a reasonable range of estimates for the market return. See Figure 5-6 for an illustration.

The range of cost of capital estimates obtained using a separate range for each of the three input variables to the CAPM, beta, risk-free rate, and market

[13] A survey of professional practices published in 1998 by Bruner, Eades, Harris, and Higgins (1998) found that 71% of textbooks/tradebooks used a historical arithmetic mean as the market risk premium and 60% of financial advisors used either a market risk premium of 7.0–7.4% (similar to the arithmetic mean) or a long-term arithmetic mean. For corporations, there was no single method that represented a consensus.

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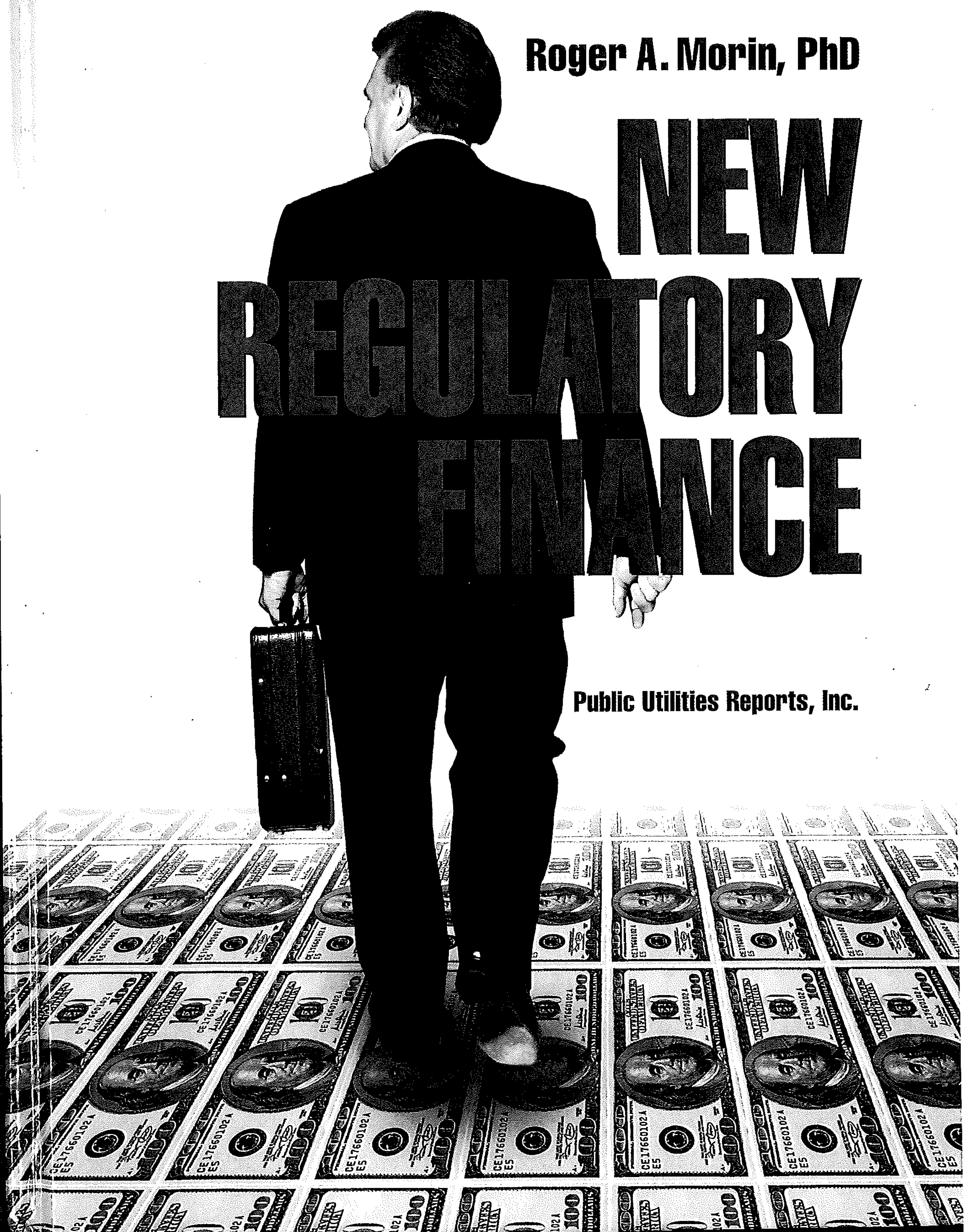

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the Miller position to recognize that the various tax rates offset some, but not all, the corporate tax advantages of debt. Line (3) adds another refinement to recognize that the corporate tax rate declines with added debt financing as the firm's added interest burden lowers its taxable income and hence its tax rate. Line (5) on the graph, which represents the dominant view of academics, nets the personal and corporate tax effects against the costs of distress. At low levels of debt, the tax effects dominate and lower the cost of capital. As the debt ratio increases, distress costs intensify at an increasing rate and eventually overtake the tax advantages, and the cost of capital increases beyond that point. Point X on the graph shows that the optimal capital structure of the hypothetical company occurs at a debt ratio of 42%.

16.4 Empirical Evidence on Capital Structure

Several researchers have studied the empirical relationship between the cost of capital, capital structure changes, and the value of the firm's securities. Comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities, summarized in Patterson (1983), include Modigliani and Miller (1958, 1963), Miller (1977), Brigham and Gordon (1968), Gordon (1974), Robichek, Higgins, and Kinsman (1973), Mehta, Moses, Deschamps, and Walker (1980), Brigham, Shome, and Vinson (1985), and Gapenski (1986). Copeland and Weston (1993) provided a comprehensive summary of the empirical evidence. Although it is not easy in such empirical tests to hold all other relevant factors constant, the evidence partially supports the existence of a tax benefit from leverage and that leverage increases firm value. The evidence also strongly favors a positive relationship between leverage and the cost of equity, which is consistent with the ModiglianiMiller propositions. However, there is still some controversy over the acceptance of the linear formulation in Equations 16-3 and 16-6. Some investigators believe the relationship is curvilinear, others believe it is linear but has a slope less than R − i.

In a study of public utility capital structures, Patterson (1983) concluded that firm value rises with leverage and revenue requirements decline at low levels of leverage, and he confirmed the existence of a cost-minimizing capital structure. Whether this optimal capital structure also minimizes revenue requirements depends on the effectiveness of regulation in passing interest tax savings through to ratepayers. Patterson also found that utilities tend to operate at a debt ratio slightly less than the optimal level, in the interest of flexibility and maintaining borrowing reserves.

The empirical effects of leverage on common equity return are summarized in Brigham, Gapenski, and Aberwald (1987). Tables 16-4 and 16-5 show the

TABLE 16-4
EFFECTS OF LEVERAGE ON COMMON EQUITY: EMPIRICAL STUDIES

Study	Result
MM (1958)	115 basis points
MM (1963)	62
Miller (1977)	237
Average	**138**

TABLE 16-5
EFFECTS OF LEVERAGE ON COMMON EQUITY: THEORETICAL STUDIES

Study	Result
Brigham and Gordon (1968)	34 basis points
Gordon (1974)	45
Robichek, Higgins, and Kinsman (1973)	75
Mehta, Moses, Deschamps and Walker (1980)	109
Gapenski (1986)	72
Brigham, Gapenski, and Aberwald (1987)	117
Average	**76**

results of empirical studies and theoretical studies obtained when the debt ratio increases from 40% to 50%. The studies report that equity costs increase anywhere from a low of 34 to a high of 237 basis points when the debt ratio increases from 40% to 50%. The average increase is 138 basis points from the theoretical studies and 76 basis points from the empirical studies, or a range of 7.6 to 13.8 basis points per one percentage increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the repercussions on equity costs.

Chapter 18 will show the results of a simulation model designed to investigate empirically the appropriate capital structure of a utility company using current market data and industry trends.

16.5 Conclusions

The benefits and costs of using debt, including taxes, agency costs, and distress costs, were identified and quantified by the various models of capital structure. Both the cost of debt and equity were seen to increase steadily with each increment in financial leverage. Despite the rise of both debt and equity costs with increases in the debt ratio, the WACC reaches a minimum as the weight of low-cost debt in the average increases. Beyond this optimal point, the low-cost and tax advantages of debt are outweighed by the rising distress costs,

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yields (2.86%–3.39%), the market risk premium (Rm – Rf) is Ibbotson's long-term, large company (S&P 500) risk premium (6.7%), and the betas are from Value Line for the companies in my comparable group (average beta 0.73). From this analysis based on current Treasury bond yields, the CAPM indicates a COE range of 7.55 percent to 7.72 percent and, based on projected Treasury bond yields, 8.08 percent to 8.25 percent. These results are generally 200 to 300 basis points below the average rates of return being allowed by state regulatory commissions for integrated electric utilities like PacifiCorp (see Table 3 above). The CAPM estimates of COE are, therefore, below any sensible test of reasonableness and should not be included in the determination of the Company's allowed ROE.

Q. **Please summarize the results of your COE analysis.**

A. Table 5 below summarizes my results:

Table 5
Summary of Cost of Equity Estimates

DCF Analysis	Indicated Cost
Constant Growth (Analysts' Growth)	9.4–9.5%
Constant Growth (GDP Growth)	9.9%–10.0%
Multistage Growth Model	9.8%–9.9%
Indicated DCF Range	9.4%–10.0%
Equity Risk Premium Analysis	Indicated Cost
Forecast Utility Debt Yield+ Equity Risk Premium	
Equity Risk Premium COE (4.45% + 5.15%)	9.6%
Current Utility Debt + Equity Risk Premium	
Equity Risk Premium COE (3.92% + 5.37%)	9.3%
PacifiCorp Cost of Equity	10.0%

Q. How should these results be interpreted to determine a reasonable ROE upon which to base rates for the Company?

A. The fair and reasonable ROE for the Company is 10.0 percent. This requested ROE, at the top of my DCF range, is appropriate given the ongoing effects of U.S. and global economic turmoil on the equity market for utility shares. Recent market turmoil and the continuing effects on capital markets make it difficult to strictly interpret quantitative model estimates for the cost of equity. While corporate interest rates have dropped to record low levels and the DCF results have declined as utility dividend yields have dropped, equity market risk aversion remains high. Under these conditions, use of a lower DCF range or equity risk premium estimates based strictly on historical risk premium relationships will understate the market cost of equity. Based on all these factors, a reasonable ROE to be used for setting rates in this case is 10.0 percent.

Q. Does this conclude your direct testimony?

A. Yes.

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Rebuttal

Q. What are the results of your updated DCF analyses?

A. My updated DCF results are shown in Exhibit No.___(SCH-15). The indicated DCF range is 9.0 percent to 9.6 percent. As I note previously, these DCF results understate PacifiCorp's COE because the dividend yields in these models have been artificially depressed by the government's stimulative monetary policies. While the market's reaction to a potential change in these policies is evident in my updated risk premium analysis as explained below, these changes are not yet reflected in my DCF results.

Q. What are the results of your updated bond yield plus equity risk premium analysis?

A. My equity risk premium studies are shown in Exhibit No.___(SCH-16). These studies indicate an ROE range of 9.6 percent to 10.0 percent. In these studies, I have added a third risk premium analysis, based on the spot interest rate data available in mid-July, designed to capture the recent FOMC policy shift and the increasing interest rate environment that the FOMC announcement has created.

Q. What do you conclude from your updated COE analyses?

A. My updated analysis shows that PacifiCorp's current COE remains approximately 10.0 percent. The lower updated DCF results, based on data from Value Line and average stock prices for April through June 2013, cannot accurately reflect the FOMC policy shift or the rising interest rates that have results. For this reason, I believe more emphasis should be placed on the current risk premium results, based on more recent interest rate data that do reflect the policy shift. As noted above, with interest rates projected for 2014, the updated risk premium analysis indicates an ROE of 10.0 percent. These results show that the Company's requested 10.0 percent ROE is reasonable and that Mr. Elgin's and Mr. Gorman's recommendations, as discussed herein, are unreasonably low.

Q. Given current economic developments, you suggest that the Commission place more emphasis on your updated risk premium results than your updated DCF results. Is this recommendation consistent with your understanding of the Commission's approach to determining ROE?

A. Yes. In Order 07 in Docket UE-100749, the Commission clarified that: "Each method has both advantages and limitations, and can be relatively more useful depending on the economic and capital market conditions at a specific time."[26] While the Commission typically relies on the DCF model to determine ROE, the Commission has been clear that it will rely on other models if economic and capital market conditions warrant. This is such a case.

Q. Did you prepare an update to the CAPM analysis you provided in your direct testimony?

A. No. None of the cost of capital witnesses in this case relied upon CAPM estimates as the basis for their ROE recommendations. There appears to be general consensus that until Fed policies change and market-based interest rates once again prevail, CAPM estimates of ROE will understate the market COE. For this reason, I did not include CAPM estimates in my updated COE analysis.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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[26] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-100749, Order 07, ¶ 22 (May 12, 2011).

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 13-028-U

DIRECT TESTIMONY

OF

SAMUEL C. HADAWAY

ON BEHALF OF

ENTERGY ARKANSAS, INC.

MARCH 1 , 2013

approach to equity risk premium analysis will consistently understate the required rate of return.

C. Summary of Analysis

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR COST OF EQUITY ANALYSIS.

A. The following Table 4 summarizes my results.

Table 4
Cost of Equity Summary

Summary of Cost of Equity Estimates	
DCF Analysis	Indicated Cost
Constant Growth (Analysts' Growth)	9.6%-9.8%
Constant Growth (GDP Growth)	9.9%-10.0%
Multistage Growth Model	9.8%
Indicated DCF Range	9.6%-10.0%
Equity Risk Premium Analysis	Indicated Cost
Forecast Utility Yield + Equity Risk Premium Equity Risk Premium ROE (5.08%+ 4.95%)	10.0%
Recent Utility Yield + Equity Risk Premium Equity Risk Premium ROE (4.55% + 5.18%)	9.7%
Resulting Cost of Equity Range	9.6%-10.0%

Q. HOW SHOULD THESE RESULTS BE INTERPRETED TO ESTIMATE THE FAIR COST OF EQUITY FOR EAI?

A. Under present market conditions, I discount the lowest results from the traditional "yield-plus-growth" DCF format and the lowest results from the risk premium model, which are derived directly from currently low, government-induced interest rates. Recent market turmoil and the continuing effects on capital markets make it difficult to strictly interpret quantitative model estimates for the cost of equity. While corporate interest rates have dropped to record low levels, and the DCF results have declined as with lower utility dividend yields, investor risk aversion remains high. Under these conditions, use of a lower DCF range or equity risk premium estimates based strictly on historical risk premium relationships will understate the market cost of equity.

Further, Company witness Ms. Cannell provides a discussion of investors' and credit rating agencies' expectations for EAI's ROE. Ms. Cannell submits that the outcome of this case could be a key factor contributing to EAI's ability to maintain its current investment grade credit rating and to sustain the Company's access to the capital markets even in difficult capital market conditions. Further, based on her analysis of investors' perspective of risk due to investment commitments being undertaken by electric utilities in general and the Company in particular, investors' perception of risk as affected by current macroeconomic conditions, and investors' expectations for a constructive regulatory environment for EAI, Ms. Cannell concludes that an ROE for EAI in the range of 10.2 to 10.4 percent would be consistent with investors' expectations for a considered decision that takes into account current market conditions, current trends in ROE awards, and EAI's increased risk in recent years.

Finally, Company witnesses McDonald and Lewis explain the substantial capital expenditures to be undertaken by EAI through 2018, including the base year of 2012. Mr. Lewis explains that in order to fund both the forecasted as well as potentially significant unexpected capital requirements, it is vital for the Company to preserve, and if possible, enhance its financial strength and flexibility. Mr. McDonald opines that this can be accomplished through an authorized ROE that supports the Company's ability to fund investments internally through increased liquidity.

Based on the quantitative results of my cost of equity analyses, my discussion of other economic data and current market conditions, as well as the factors and circumstances discussed by the other Company witnesses, an ROE range of 10.2 percent to 10.4 percent is reasonable for establishing rates in this proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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IX. UPDATED ROE ANALYSIS

Q. HAVE YOU UPDATED YOUR ROE ANALYSIS TO TAKE INTO ACCOUNT RECENT DATA AND THE CURRENT CONDITIONS IN THE CAPITAL MARKETS?

A. Yes. As discussed previously, I have updated my ROE analysis for current market conditions using the same methodologies that I employed in my previous analysis.

Q. WHAT ARE THE RESULTS OF YOUR UPDATED DCF ANALYSES?

A. My updated DCF results are shown in EAI Exhibit SCH-10. As I discussed previously, the results for this updated analysis are somewhat lower than the DCF estimates I provided in my direct testimony (EAI Exhibit SCH-6). Given the 70 basis point increase in interest rates that has occurred since April, such lower DCF results do not meet the basic test of reasonableness. For this reason, I recommend that more weight should be given to my updated risk premium analysis, which provides, although still low, ROE estimates that are at least in part consistent with the increasing interest rate trend that is now occurring.

Q. WHAT ARE THE RESULTS OF YOUR UPDATED BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. My updated risk premium analysis is presented in EAI Exhibit SCH-11. My updated risk premium models indicate an ROE range of 10.0 percent to 10.4 percent. The low end of the range is based on the average Baa Utility interest rate for the three months ended July 2013. The upper end of the range is based on the Bloomberg Forward Curve projected rate for December 31, 2014. The intermediate result based on recent Baa spot rates, is 10.2 percent. The projected and spot rates reflect the Fed's more recent policy position and, therefore, are more reasonable estimates of the cost of equity.

Q. WHAT DO YOU CONCLUDE FROM YOUR UPDATED ROE ANALYSES?

A. Given the increasing interest rate environment that now exists, the Company's requested 10.4 percent ROE is reasonable. The lower updated DCF results, based on data from Value Line and average stock prices for May-July 2013, cannot accurately reflect the FOMC policy shift or the rising interest rates that have resulted. For this reason, I believe more emphasis should be placed on the current risk premium results, based on more recent interest rate data that do reflect the policy shift. As noted above, factoring in interest rate projections for 2014, the updated risk premium analysis indicates an ROE of 10.4 percent. My updated analysis confirms that the recommendations of the other parties, as discussed herein, are unreasonably low.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.