BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan	)))))	Case No. 16-1852-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority	)))	Case No. 16-1853-EL-AAM

OHIO POWER COMPANY'S APPLICATION TO AMEND ITS ELECTRIC SECURITY PLAN

WORKPAPERS
For Adrien M. McKenzie

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DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA

NO.	Title
WP-1	Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014)
WP-2	Moody's Investors Service, "Credit Opinion: Ohio Power Company," *Global Credit Research* (May 12, 2015)
WP-3	Standard & Poor's Corporation, "Summary: Ohio Power Co.," *Research* (May 8, 2014)
WP-4	Barnato, Katy, "Fed's Plosser: Low rates 'should make us nervous'," CNBC (Nov. 11, 2014)
WP-5	Federal Reserve Statistical Release, "Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks," H.4.1
WP-6	Poole, William, "Prospects for and Ramifications of the Great Central Banking Unwind," Financial Analysts Journal (November/December 2013)
WP-7	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006)
WP-8	Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974)
WP-9	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006)
WP-10	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006)
WP-11	*Morningstar*, "Ibbotson SBBI 2015 Classic Yearbook," at pp. 99, 108
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WP-13	Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985)
WP-14	Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992)
WP-15	Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, at 128 (2006)
WP-16	Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985
WP-17	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 335 (2006)
WP-18	Roger A. Morin, "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 166 (1994)

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WP-19	Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1
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MOODY'S
INVESTORS SERVICE

US Regulated Utilities

Regulation Will Keep Cash Flow Stable As Major Tax Break Ends

Our outlook for the US regulated utility industry is stable. This outlook reflects our expectations for the fundamental business conditions in the industry.

- **Cost-recovery mechanisms, coupled with annual base-rate increases, will keep the ratio of industry-wide cash flow to debt at about 18%, within our range for a stable outlook.** Favorable rate orders are part of what we view as a broader shift toward stronger regulatory support for the industry, all the more important this year given the end of bonus depreciation. Industry regulation is the most important driver of our outlook.
- **Ratemaking mechanisms, such as revenue decoupling and riders, allow utilities to recover costs faster and improve the quality, predictability and stability of cash flow.** The ratio of cash flow to gross profit for a peer group of 122 US operating companies has been more stable on a year-over-year basis since 2009, as the use of riders in regulatory agreements has become more commonplace.
- **We are also seeing signs of improved regulatory support in historically contentious states, such as Connecticut and Illinois.** Stronger recovery mechanisms put in place last year for Connecticut Natural Gas Corp. (A3 stable) and Commonwealth Edison Co. (Baa1 stable) in Illinois will likely make cash flow more predictable for utilities in each state. This marks a turnaround in both states, where regulatory support was lacking for certain cost-recovery provisions in the past.
- **Stagnant customer demand is leading some utilities to pursue shareholder growth through financial engineering.** Some companies are restructuring their businesses by creating master limited partnerships and "yieldcos" to defend their historically high equity multiples. For now, credit risks are limited but so are any benefits for bondholders, and these structures may weaken sponsor credit quality over time.
- **What could change our outlook.** We could shift our outlook to positive if the ratio of cash flow to debt rose toward 25% on a sustainable basis, which could happen if return on equity rises or utilities deleverage significantly. A more contentious regulatory environment that resulted in a material deterioration in cash flow, such that the ratio fell to 13%, could cause us to have a negative outlook.

Supportive regulatory relationships drive our stable outlook

Regulatory support will help US electric and gas utilities maintain stable credit profiles in 2014, even with stagnant customer demand and without the cash-flow boost from bonus depreciation.

Fundamentally, the regulatory environment is the most important driver of our outlook because it sets the pace for cost-recovery. Favorable rate orders, even in states where utilities have had contentious regulatory relationships in the past, are part of what we view as a broader shift toward stronger regulatory support for the industry.

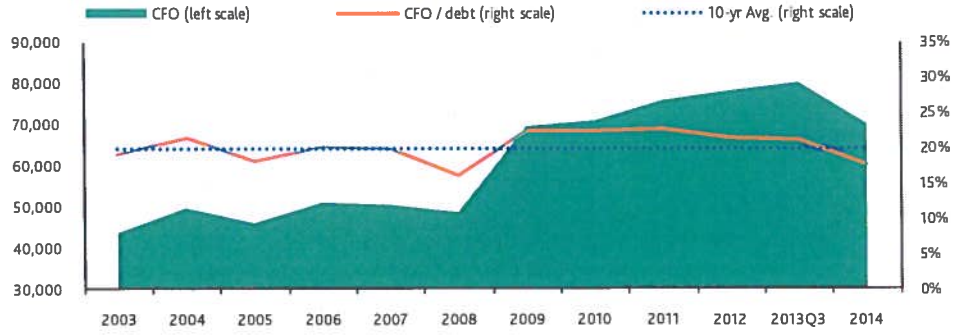
The improved regulatory framework, led by special cost-recovery mechanisms and annual base-rate increases, is all the more important this year for two reasons. First is the end of bonus depreciation, a temporary tax break that expired on December 31. We incorporate a view that bonus depreciation will not be extended; however, various corporate sectors are currently lobbying for the extension in 2014. Second is stagnant customer demand, which is also leading some utilities to pursue shareholder growth through financial engineering (please see page 6).

As Exhibit 1 shows, the ratio of cash flow to debt will decline this year to 18%, just below the 10-year trend line but within our range for a stable outlook. The decline is largely because of higher cash taxes, but utilities can still get some tax relief in 2014 by applying net operating loss carry-forwards (from factors unrelated to bonus depreciation) from past years to this year's tax payments—an option they didn't use when bonus depreciation was in effect.

We would likely shift our outlook to positive if the ratio of cash flow to debt rose to 25%, although that would take a marked increase in regulatory-allowed ROE levels or steps by utilities to scale back their dividend and stock-repurchase plans. A more contentious regulatory environment or a widespread adoption of more-aggressive financial strategies resulting in a material deterioration in cash flow, such that the ratio fell to 13%, would likely lead to a negative outlook.

EXHIBIT 1

Cash Flow to Debt Will Hover Below the 10-Year Average



Notes: Figures are in thousands of US dollars. A list of the 122 utilities included in our analysis starts on page 7. Data for the third quarter of 2013 are the latest available. Data for 2014 are our estimates.
Source: *Moody's Investors Service*

Improved regulatory environment means stable, more predictable cost-recovery

The US regulatory environment has improved significantly in the past year, providing for faster and more-certain cost-recovery in 2014.

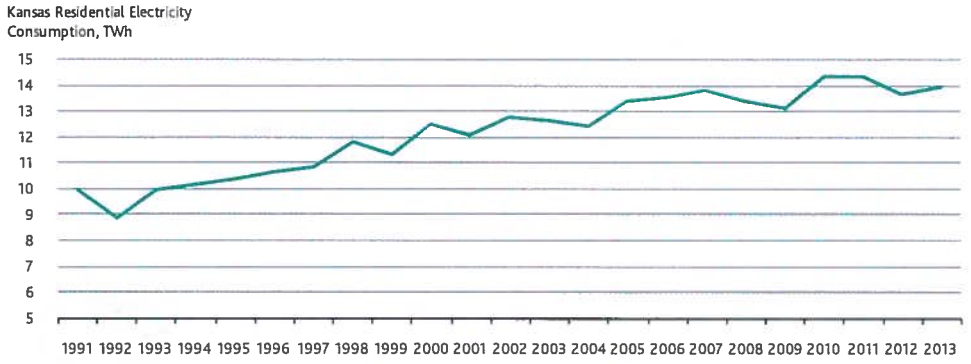
Puget Sound Energy Inc.'s (PSE; Baa1 stable) June 2013 rate order is a good example. Its regulator, the Washington Utilities and Transportation Commission, approved the decoupling of electric and gas revenue from sales volume, and a property-tax tracker that provides more-efficient recovery of property-tax expense. The commission acknowledged a need to reduce regulatory lag times by expediting the utility's rate filings and offering more real-time true-up of costs during rate filings. The regulator also provided the company with forward-looking annual revenue adjustments (about 3% for electric and 2% for gas) over the next three years. As a result of these changes, we expect that Puget Sound's cash-flow-to-debt ratio will continue to surpass 20%, exceeding the industry average, even without the cash-flow benefit of bonus depreciation.

Another example is Westar Energy Inc.'s (Baa1 stable) 2013 abbreviated rate case with the Kansas Corporation Commission. In addition to providing incremental cost-recovery for environmental upgrades, the regulator allowed Westar to increase its monthly fixed charge on customer bills. This movement in rate design will allow Westar to recover a greater portion of its fixed costs through fixed rates, rather than volumetric rates, thereby reducing Westar's dependency on selling higher volumes to recover fixed costs. The shift to a $12 residential monthly fixed charge from $9 will be a benefit amid flat customer demand in Kansas over the past three years (see Exhibit 2).

EXHIBIT 2

Demand for Electricity Has Been Stagnant in Kansas

Actual Consumption



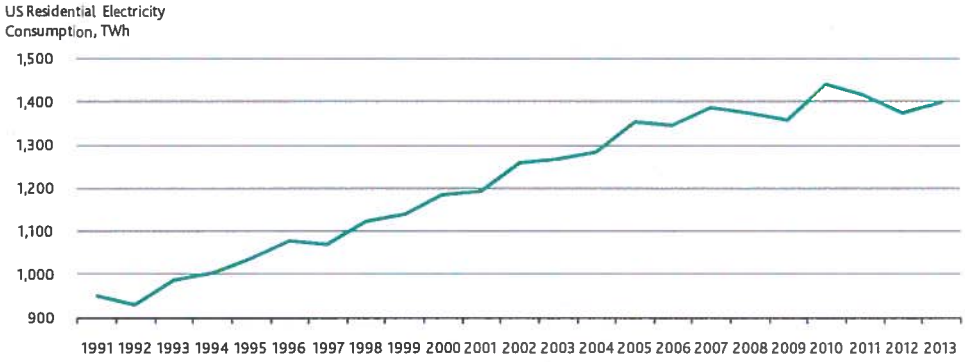
Notes: TWh stands for terawatt hour. 2013 US Energy Information Administration (EIA) data are through October 2013. Our estimates for November and December 2013 are based on historical trends.
Source: US Energy Information Administration

As demand for electricity wanes, rate structures that are tied more closely to volumetric charges than to fixed charges will threaten the gross profits of most electric and gas utilities. Exhibit 3 below shows the drop-off in US electricity demand since 2010, largely attributable to weather and slow economic growth as well as conservation and efficiency measures.

EXHIBIT 3

Demand for Electricity Is Slow to Rebound

Actual Consumption



Note: 2013 EIA data is through October 2013. Our estimates for November and December 2013 are based on historical trends.
Source: US Energy Information Administration

The industry's financial profile is becoming more predictable and steady because of these special recovery mechanisms that supplement cash recovery between general rate cases. As Exhibit 4 shows, the average ratio of cash flow from operations to gross profit had a standard deviation of 2.4% on a year-over-year basis between 2003 and 2008. This compares with a 1.1% standard deviation on average between 2009 and the third quarter of 2013, the latest data available, a period marked by a more pervasive use of cost-recovery mechanisms throughout the US.

EXHIBIT 4

Cost-Recovery Mechanisms Make Cash Flow More Predictable

Year	CFO / Gross Profit	Standard Deviation Rolling Two-Year Average	Average Standard Deviation
2003	30.9%		
2004	37.0%	4.3%	
2005	34.0%	2.1%	
2006	37.3%	2.4%	
2007	34.9%	1.7%	
2008	32.9%	1.4%	2.4%
2009	44.9%		
2010	42.5%	1.7%	
2011	44.8%	1.6%	
2012	44.3%	0.3%	
3Q13	43.0%	0.9%	1.1%

Note: The latest data available are for the third quarter of 2013.
Source: Moody's Investors Service

Cost-recovery improves, but not without exceptions

Most regulated electric and gas utilities in the US have shown evidence of improved regulatory relationships. Apart from Puget Sound's and Westar's cost-recovery improvements, we have seen regulatory improvement in Illinois and Connecticut, states in which the relationships between regulators and utilities have been somewhat contentious.

Stronger recovery mechanisms put in place late last year in both Illinois and Connecticut will make utility cash flow more predictable. For example, in Illinois, **Commonwealth Edison**'s (ComEd) cash flow to debt coverage will start improving in 2014, supported by the adoption of a version of formula ratemaking (i.e., the Energy Infrastructure Modernization Act, or "EIMA," which helps define various aspects of rate structure and cost-recovery in Illinois). The implementation of EIMA will make cost-recovery more tied to factors determined by a formula and less tied to rate-case negotiations (the results of which are less predictable).

Similarly, the Connecticut legislature in 2013 passed the Comprehensive Energy Strategy, which encourages the use of decoupling mechanisms and infrastructure replacement riders (i.e., the Distribution Integrity Management Program, or DIMP), while promoting growth of local distribution companies (LDCs) through customer conversions. These measures are subject to approval by the Public Utilities Regulatory Authority in rate-case proceedings, but were approved in **Connecticut Natural Gas**'s (CNG; A3 stable) December 2013 rate case. We expect decoupling, DIMP and conversion incentives to be applied to all LDCs in the state going forward.

These moves mark a turnaround in both states from past years, when regulatory support was lacking for certain cost-recovery provisions and when general rate case outcomes were deemed less than favorable from an investor perspective. For example, the Illinois legislature passed the EIMA in 2011, but the Illinois Commerce Commission did not fully implement it, initially, which made future cost-recovery for ComEd uncertain. Likewise, Connecticut LDCs had few tracking mechanisms and were exposed to declining customer usage in rate design. Now, through the adoption of EIMA in ComEd's rate structure (clarified by Senate Bill 9 in 2013) and CNG's implementation of decoupling and the DIMP, the financial profiles of both companies will likely improve.

These cost-recovery improvements are part of the broader trend we are seeing in the industry, but there are a few high-profile exceptions. Entergy Corp. (Baa3 stable), which has a history of contentious regulatory relationships in Arkansas and Texas, is one example.

Last year, Entergy Arkansas Inc. (Baa2 stable) put forth a nearly $145 million rate request but received about $81 million (the Arkansas Public Service Commission did allow a new cost-recovery rider for certain regional transmission expenses, however). Entergy Texas Inc. (Baa3 stable) requested about $53 million in rate increases for 2014, but the Texas Public Utilities Commission's (PUC) staff recommended a rate increase of a little more than $3 million. The PUC has not issued a final decision.

Another high-profile exception is Consolidated Edison of New York's (A2 stable) pending rate settlement, which calls for a two-year freeze on electric rates and a three-year rate freeze on gas and steam rates. Although the rate freeze would curb Consolidated Edison of New York's earnings, the settlement is credit neutral because of the provision for reasonable recovery of deferred storm costs related to Hurricane Sandy and other investments.

This year, one utility that might also buck the positive trend is Jersey Central Power & Light Co. (JCP&L; Baa2 negative). JCP&L has been the target of public criticism over its handling of outages related to Hurricane Sandy, besides allegations of over-earning. The staff of the New Jersey Board of Public Utilities has proposed that base rates be cut by $207 million (not considering recovery of storm costs, which will be addressed in a separate rate proceeding). This compares with the company's request for an increase of $11 million (again, not considering storm costs).

JCP&L's financial flexibility and financial metrics have already been weakened by costs associated with Hurricane Sandy, so a material rate reduction could hurt JCP&L's rating. If JCP&L can bring its ratio of cash flow to debt to at least 14% despite a rate decrease, then our rating outlook could stabilize. JCP&L had 12% cash flow to debt through the 12 months ended the third quarter of 2013.

More utilities are turning to financial engineering

Against a backdrop of stagnant demand, some utility holding companies are turning to forms of financial engineering, such as creating master limited partnerships (MLPs) and so-called yieldcos, to defend their historically high equity multiples. For the few companies that have proceeded with these strategies so far, the credit impact is neutral because the vehicles are small relative to the corporate sponsor's consolidated credit profile. But longer term, credit risks could increase if these companies eventually lose too much cash flow from their most stable assets and don't reduce debt enough to rebalance their capital structures.

We expect some more companies to go public with these financial-engineering vehicles this year. The joint venture among OGE, CenterPoint and ArcLight—the Enable Midstream Partners MLP—plans to complete an initial public offering in the first quarter. Dominion Resources Inc. (Baa2 stable) expects to publicly offer its MLP by mid-year. In addition, NextEra Energy Inc. (Baa1 stable) expects to make a decision whether to form a yieldco by then.

Meantime, several companies have pursued acquisitions outside of their core utility holdings and service territories, like MidAmerican Energy Holdings Co. (A3 stable), TECO Energy Inc. (Baa1 stable), and Avista Corp. (Baa1 stable). This trend is bound to continue as companies try to expand their regulated footprint and achieve regulatory diversity. We expect that most M&A activity in 2014 will be conservatively financed much like these transactions, which included equity financings.

EXHIBIT 5

Regulated Utilities: M&A Activity

	Acquirer			Acquiree				
Acquirer / Acquiree	Revenue	CFO	Debt	Revenue	CFO	Debt	Financing	Credit Implication
MidAmerican Energy Holdings Co. / NV Energy, Inc.	$12,373	$505	$4,255	$2,930	$794	$5,125	$5.6 billion in debt & equity	Positive; no ratings actions
TECO Energy, Inc. / New Mexico Gas Company	$2,851	$680	$3,156	$332	$65	$250	$950 million in debt, equity, & cash	Affirmed TECO Energy ratings
Avista Corp / Alaska Energy and Resources Company (AERC)	$1,581	$295	$1,739	$42	$20	$115	$170 million in equity	Neutral for Avista
Fortis, Inc. / UNS Energy Corporation	$3,654	$976	$5,783	$1,483	$400	$ 1,937	$4.3 billion in debt & equity	Slightly positive for UNS Energy Corporation; no ratings action

Notes: Financials are in millions, as of the 12 months ended September 30, 2013. AERC financials are based on Alaska Electric Light and Power Co. (AELP) 2012 FERC Form 1 data. Fortis and New Mexico Gas financials are as reported as of fiscal 2012. We expect TECO Energy will assume $200 million of debt already existing at New Mexico Gas Company. We expect Fortis to assume approximately $1.8 billion of debt already existing at UNS Energy Corporation. In addition, we expect Fortis to finance the UNS acquisition in a manner similar to historical precedent, with a balanced mix of debt and equity issued upstream from the utility (we expect Fortis to keep UNS's current capital structure in place).
Sources: Fortis Inc. Annual Report, AELP 2012 FERC Form 1, SNL, Moody's Financial Metrics

Appendix: Peer Group

Moody's Financial Metrics

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
Integrated	Alabama Power Company	A1	Stable	26%
	ALLETE, Inc.	A3	Stable	22%
	Appalachian Power Company	Baa1	Stable	17%
	Arizona Public Service Company	A3	Stable	28%
	Avista Corp.	Baa1	Stable	18%
	Black Hills Power, Inc.	A3	Stable	22%
	Cleco Power LLC	Baa1	Positive	19%
	Consumers Energy Company	(P)A3	Stable	27%
	Dayton Power & Light Company	Baa3	Stable	34%
	DTE Electric Company	A2	Stable	24%
	Duke Energy Carolinas, LLC	A1	Stable	23%
	Duke Energy Corporation	A3	Stable	15%
	Duke Energy Florida, Inc.	A3	Stable	21%
	Duke Energy Indiana, Inc.	A2	Stable	16%
	Duke Energy Kentucky, Inc.	Baa1	Stable	23%
	Duke Energy Ohio, Inc.	Baa1	Stable	25%
	Duke Energy Progress, Inc.	A1	Stable	23%
	El Paso Electric Company	Baa1	Stable	25%
	Empire District Electric Company (The)	Baa1	Stable	20%
	Entergy Arkansas, Inc.	Baa2	Stable	19%
	Entergy Louisiana, LLC	Baa1	Stable	17%
	Entergy Mississippi, Inc.	Baa2	Stable	16%
	Entergy New Orleans, Inc.	Ba2	Stable	20%
	Entergy Texas, Inc.	Baa3	Stable	14%
	Florida Power & Light Company	A1	Stable	32%
	Georgia Power Company	A3	Stable	25%
	Gulf Power Company	A2	Stable	26%
	Hawaiian Electric Company, Inc.	Baa1	Stable	17%
	Idaho Power Company	A3	Stable	16%
	Indiana Michigan Power Company	Baa1	Stable	21%
	Interstate Power and Light Company	A3	Stable	18%
	Kansas City Power & Light Company	Baa1	Stable	18%
	Kansas City Power & Light Company - Greater MO	Baa2	Stable	22%
	Madison Gas and Electric Company	A1	Stable	30%
	MidAmerican Energy Company	A1	Stable	24%
	Mississippi Power Company	Baa1	Stable	14%
	Nevada Power Company	Baa1	Stable	18%

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
	Northern States Power Company (Minnesota)	A2	Stable	25%
	Northern States Power Company (Wisconsin)	(P)A2	Stable	30%
	NorthWestern Corporation	A3	Stable	19%
	Ohio Power Company	Baa1	Stable	32%
	Oklahoma Gas & Electric Company	A1	Stable	27%
	Otter Tail Power Company	A3	Stable	24%
	Pacific Gas & Electric Company	A3	Stable	25%
	PacifiCorp	A3	Stable	23%
	Portland General Electric Company	A3	Stable	25%
	Public Service Co. of North Carolina, Inc.	A3	Stable	25%
	Public Service Company of Colorado	A3	Stable	23%
	Public Service Company of New Hampshire	Baa1	Stable	20%
	Public Service Company of New Mexico	Baa2	Positive	21%
	Public Service Company of Oklahoma	A3	Stable	27%
	Puget Sound Energy, Inc.	Baa1	Stable	21%
	San Diego Gas & Electric Company	A1	Stable	21%
	Sierra Pacific Power Company	Baa1	Stable	16%
	South Carolina Electric & Gas Company	Baa2	Stable	17%
	Southern California Edison Company	A2	Stable	30%
	Southern Indiana Gas & Electric Company	A2	Stable	28%
	Southwestern Electric Power Company	Baa2	Stable	18%
	Southwestern Public Service Company	Baa1	Stable	21%
	Tampa Electric Company	A2	Stable	32%
	Tucson Electric Power Company	Baa1	Stable	19%
	Union Electric Company	(P)Baa1	Stable	22%
	UNS Energy Corporation	Baa2	Stable	19%
	Virginia Electric and Power Company	A2	Stable	27%
	Westar Energy, Inc.	Baa1	Stable	16%
	Wisconsin Electric Power Company	A1	Stable	17%
	Wisconsin Power and Light Company	A1	Stable	31%
	Wisconsin Public Service Corporation	A1	Stable	26%
T&Ds	AEP Texas North Company	Baa1	Stable	22%
	Ameren Illinois Company	(P)Baa1	Stable	26%
	Atlantic City Electric Company	Baa2	Stable	15%
	Baltimore Gas and Electric Company	A3	Stable	19%
	CenterPoint Energy Houston Electric, LLC	A3	Stable	16%
	Central Hudson Gas & Electric Corporation	A2	Stable	29%
	Central Maine Power Company	A3	Stable	27%
	Cleveland Electric Illuminating Company (The)	Baa3	Stable	15%
	Commonwealth Edison Company	Baa1	Stable	21%

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
	Connecticut Light and Power Company	Baa1	Stable	13%
	Consolidated Edison Company of New York, Inc.	A2	Stable	23%
	Delmarva Power & Light Company	Baa1	Stable	17%
	Duquesne Light Company	A3	Stable	26%
	Jersey Central Power & Light Company	Baa2	Negative	18%
	New York State Electric and Gas Corporation	A3	Stable	26%
	Niagara Mohawk Power Corporation	A3	Stable	23%
	NSTAR Electric Company	A2	Stable	29%
	Ohio Edison Company	Baa2	Stable	25%
	Oncor Electric Delivery Company LLC	Baa3	Stable	20%
	Orange and Rockland Utilities, Inc.	A3	Stable	21%
	PECO Energy Company	A2	Stable	30%
	Pennsylvania Electric Company	Baa2	Stable	18%
	Pennsylvania Power Company	Baa2	Stable	37%
	Potomac Edison Company (The)	Baa3	Stable	19%
	Potomac Electric Power Company	Baa1	Stable	16%
	Public Service Electric and Gas Company	A2	Stable	25%
	Rochester Gas & Electric Corporation	Baa1	Stable	26%
	Texas-New Mexico Power Company	Baa1	Positive	26%
	Toledo Edison Company	Baa3	Stable	8%
	United Illuminating Company	Baa1	Stable	20%
	West Penn Power Company	Baa2	Stable	25%
	Western Massachusetts Electric Company	A3	Stable	23%
LDCs	Atlanta Gas Light Company	A2	Stable	30%
	Atmos Energy Corporation	A2	Stable	23%
	Berkshire Gas Company	Baa1	Stable	29%
	Connecticut Natural Gas Corporation	A3	Stable	26%
	DTE Gas Company	Aa3	Stable	24%
	Indiana Gas Company, Inc.	A2	Stable	27%
	Laclede Gas Company	(P)A3	Stable	26%
	New Jersey Natural Gas Company	(P)Aa2	Stable	19%
	Northern Illinois Gas Company	A2	Stable	49%
	Northwest Natural Gas Company	(P)A3	Stable	20%
	Piedmont Natural Gas Company, Inc.	A2	Stable	23%
	Questar Gas Company	A2	Stable	25%
	SEMCO Energy, Inc.	Baa1	Stable	15%
	SourceGas LLC	Baa2	Stable	14%
	South Jersey Gas Company	A2	Stable	21%
	Southern California Gas Company	A1	Stable	32%
	Southern Connecticut Gas Company	Baa1	Stable	22%

Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
UGI Utilities, Inc.	A2	Stable	27%
UNS Gas, Inc.	Baa1	Stable	27%
Washington Gas Light Company	A1	Stable	35%
Wisconsin Gas LLC	A1	Stable	28%
Yankee Gas Services Company	Baa1	Stable	18%

Source: Moody's Investors Service

Moody's Related Research

Industry Outlooks:

- US Regulated Utilities: Regulation Provides Stability as Business Model Faces Challenges, July 2013 (156754)
- US Regulated Utilities: Regulatory Support, Low Natural Gas Prices Maintains Stability, February 2013 (149379)
- US Unregulated Power: Headwinds continue for the merchant power players, July 2013 (156302)
- US Coal Industry Outlook Stabilizes as Business Conditions Hit Bottom, August 2013 (157309)
- Global Oil & Gas: Persistent High Oil Prices Keep Industry Robust, but Global Supply Increasing (Summary), December 2013 (160980)

Special Comment:

- US utility sector upgrades driven by stable and transparent regulatory frameworks, January 2014 (163726)
- YieldCos: Fantastic for Shareholders; Less So for Bondholders, November 2013 (160121)
- Planned Capital Expenditures Set to Fall in 2015, And Modestly Decline Thereafter, October 2013 (158945)
- US Telecommunications and Regulated Utilities: End of Bonus Depreciation Could Prompt Cuts in Capital Spending, Dividends, September 2013 (157572)
- US Local Gas Distribution Companies: Lower risks and unique growth opportunities versus electric utility peers, May 2013 (153018)
- The Prospect of US LNG Exports Influences Pricing and Gas Markets Worldwide, May 2013 (151819)
- US Extends Tax Credit for Wind Power, a Credit Positive for Developers and Utilities, January 2013 (148915)

Rating Methodology:

- Regulated Electric and Gas Utilities, December 2013 (157160)

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Analyst Contacts:

NEW YORK	+1.212.553.1653
Jeffrey F. Cassella *Analyst* jeffrey cassella@moodys.com	+1.212.553.1665
Lesley Ritter *Analyst* lesley.ritter@moodys.com	+1.212.553.1607
Toby Shea *Vice President - Senior Analyst* toby.shea@moodys.com	+1.212.553.1779
Swami Venkataraman *Vice President - Senior Credit Officer* swami.venkataraman@moodys.com	+1.212.553.7950
Susana Vivares *Vice President - Senior Analyst* susana.vivares@moodys.com	+1.212.553.4694
Larry Hess *Managing Director - Utilities* larry.hess@moodys.com	+1.212.553.3837
TORONTO	+1.416.214.1635
Gavin MacFarlane *Vice President – Senior Analyst* gavin.macfarlane@moodys.com	+1.416.214.3864

MOODY'S INVESTORS SERVICE

Report Number: 164268

Author
Ryan Wobbrock

Production Specialist
Cassina Brooks

MOODY'S
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Credit Opinion: Ohio Power Company

Global Credit Research - 12 May 2015

Canton, Ohio, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
Parent: American Electric Power Company, Inc.	
Outlook	Stable
Senior Unsecured	Baa1
Jr Subordinate Shelf	(P)Baa2
Commercial Paper	P-2

Contacts

Analyst	Phone
Susana Vivares/New York City	212.553.4694
William L. Hess/New York City	212.553.3837

Key Indicators

[1]**OhioPowerCompany**

	3/31/2015(L)	12/31/2014	12/31/2013	12/31/2012	12/31/2011
CFO pre-WC + Interest / Interest	**6.1x**	**5.6x**	**5.1x**	**5.4x**	**5.6x**
CFO pre-WC / Debt	**24.3%**	**22.1%**	**26.1%**	**23.3%**	**24.5%**
CFO pre-WC - Dividends / Debt	**22.5%**	**20.8%**	**15.1%**	**16.7%**	**11.2%**
Debt / Capitalization	**44.6%**	**44.8%**	**53.8%**	**40.0%**	**42.0%**

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics

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

Opinion

Rating Drivers

Constructive regulatory outcomes in Ohio continue through market transition

Consolidating into a lower-risk transmission and distribution utility through 2015

Slow economic recovery in Ohio, but continuous improvements are expected

Financial metrics will weaken during transition period in 2015 and 2016

Corporate Profile

Ohio Power Company (OPCo: Baa1, stable), a wholly owned subsidiary of American Electric Power Company (AEP: Baa1, stable), is engaged in transmission and distribution (T&D) services to approximately 1.5 million customers in Ohio at cost-based rates approved by the Public Utility Commission of Ohio (PUCO) or by the Federal Energy Regulatory Commission (FERC). OPCo has approximately $4.0 billion in rate base (15% of AEP's total jurisdictional rate base) with an above average pro-forma earned ROE of 12.6%.

OPCo provides power and capacity to its customers who have not switched electric providers. Effective January 1, 2014 OPCo began purchasing power from both affiliated and non-affiliated entities which are subject to auction requirements and approval to meet energy and capacity needs of customers. OPCo is a member of PJM.

Rating Rationale

OPCo's Baa1 rating reflects a low risk regulated T&D business with adequate cash flow metrics benefiting from a service territory in post-recessionary recovery and a credit supportive regulatory framework. OPCo's cash flow metrics remain adequate for the rating due to reduced debt levels stemming from the corporate separation resulting in cash flow pre-working capital (CFO pre-WC) to debt in the high teens, and debt to capitalization in the high forties.

DETAILED RATING CONSIDERATIONS

CONSTRUCTIVE REGULATORY OUTCOMES IN OHIO CONTINUE THOUGH MARKET TRANSITION

We view the Ohio regulatory environment as supportive to credit quality. On February 25, 2015 PUCO approved the implementation of electricity security plant (ESP) III covering the period June 1, 2015 through May 31, 2018. The new ESP will require OPCo to conduct six auctions to provide 100% of its standard service offer (SSO); the continuation of the distribution investment rider (DIR) based on a 10.2% return on equity, with associated capital investments carrying cost recovery of $124 million in 2015, around $146 million in 2016, $170 million in 2017, and about $100 million in 2018; the continuation of the enhanced service reliability rider (ESRR), storm damage recovery rider (SDRR), and a by-passable alternative energy rider (AER) reflecting the costs associated with the procurement of renewable energy credits; and, the proposed purchase-of-receivables mechanism. The Commission rejected the proposed sustained and skilled workforce (SSWR) rider. OPCo is currently subject to the terms of ESP II, which will expire on May 31, 2015.

In its February 25th ruling, PUCO also rejected OPCo's request for a rate rider and power purchase agreement (PPA) designed to guarantee income for its share of two coal-fired power plants operated by Ohio Valley Electric Corp. (OVEC, Baa3 stable). OPCo has a contractual commitment to roughly 20% of OVEC's coal-fired Kyger Creek and Clifty Creek plants. The PUCO authorized OPCo to implement a placeholder PPA rider, but declined to approve recovery of any costs at this time. OPCo is required to justify any requested PPA-related cost recovery in a future filing with the PUCO. This includes the financial necessity, as well as a plan forward under future environmental compliance. In July 2014 OPCo submitted an application to PUCO proposing an additional 2,671 MW to be added into a new PPA with AEP Generation Resources (AGR: not rated) over the life of the generation units. The PUCO has taken no action in this case and a decision is not expected until the second half of 2015. Pending PJM reforms and a similar FirstEnergy Corp's (Baa3, stable) case are important factors in evaluating the potential outcome of the OPCo case.

Effective January 1, 2014, FERC approved the power supply agreement between AGR and OPCo to secure available capacity for OPCo's switched and non-switched retail load from the period January 1, 2014 through May 31, 2015; and the bridge agreement among AGR , Appalachian Power Company (Baa1, stable), Kentucky Power Company (Baa2, stable), Indiana Michigan Power Company (Baa1 stable), OPCo, and AEP Service corporation (AEPSC, not rated) to address open commitments related to the termination of the previous Interconnection Agreement and responsibilities to PJM.

CONSOLIDATING INTO A LOWER RISK TRANSMISSION AND DISTRIBUTION UTILITY

We generally view the business risk of a T&D lower than that of a vertically integrated utility because of limited activities resulting in greater certainty of cash flows, a credit positive. However, a prolonged period of recovery costs associated with many of the riders or trackers under OPCo's ESPs would be credit negative because the associated securitization burden would remain on OPCo's balance sheet longer.

Moody's has historically evaluated OPCo's financial performance relative to the standard grid within the Regulated Electric and Gas Utilities methodology, which is customarily applied to vertically integrated utilities. OPCo's indicated rating under the standard grid based on historical and projected results (next 12-18 months) is Baa1.

However, we acknowledge OPCo's recent business transformation into a low risk regulated T&D and beginning in 2015 have revised our view to reflect this shift, placing OPCo under the low business risk grid within the methodology. That said, it would be unlikely that switching to the low risk business grid would result in any immediate rating upgrades for OPCo.

OHIO'S ECONOMIC RECOVERY WILL DEEPEN IN 2015; THOUGH ENERGY SECTOR PERFORMACE IS CLOUDY

Ohio's recovery has accelerated in the past several months but still lags behind those of the Midwest and the nation, according to Moody's Economy.com. Energy exploration, specifically in the Utica shale, health care, professional services and manufacturing have emerged as key growth drivers which will deepen the recovery in 2015 and are expected to drive a decrease in the unemployment rate to 4.8% by 2016 from 7.3% in 2013.

OPCo's principal industries include primary and fabricated metals, petroleum refining, chemical manufacturing, rubber and plastics products, mineral product and food products. Overall total retail sales as of December 2014 were 44,701 GWH, lower than their historical averages primarily due to the shutdown of a large aluminum smelter combined with energy efficiency and demand response initiatives set in 2008. On a positive note, excluding the aluminum smelter, industrial load was up, with gigawatts hours going from 14,008 in 2013 to 14,529 in 2014. The revenue impact from reduced sales resulting from these programs are offset by PUCO-approved trackers.

HISTORICALLY ROBUST METRICS WILL WEAKEN DURING TRANSITION PERIOD

OPCo's key financial credit metrics remain within the grid-indicated rating category for its Baa1 rating. For year-end 2013 and LTM Q1 2015 the interest coverage ratio was 5.6x and 6.1x, CFO pre-WC to debt (leverage ratio) was 22.1% and 24.3%, CFO pre-WC minus dividends to debt (RCF ratio) was 20.8% and 22.5%; and debt to capitalization was 45% for both periods. OPCo's CFO pre-WC has slightly increased from $600 million in 2014 to about $670 in LTM Q1 2015 which could imply that OPCo's cash flow metrics will stabilize reflecting the nature of the T&D business. We think capital investments will remain at an average $600 million per year.

For the next 18-24 months Moody's expects OPCo's metrics to continue being pressured due to the remaining recovery costs, which are expected to be fully recovered by May 2018. The restructuring has led to a decrease in leverage at OPCo, a credit positive. However, this is offset by the loss of revenues and deferred income tax benefits leading to a decrease in CFO pre-WC. We expect the interest coverage ratio to range from 5.3x to 5.8x; leverage ratio from 19% to 24%; RCF ratio from 13% - 18%; and debt to capitalization from 42% - 47%.

Liquidity

OPCo's liquidity is adequate. OPCo participates in the AEP Utility Money Pool with a borrowing limit of $400 million, which provides access to the parent company's liquidity. At year-end 2014, OPCo's loans to the utility pool were $312 million. OPCo also utilizes AEP's receivable securitization facility for its Ohio receivables. OPCo has $350 million in senior notes coming due in June of 2016 and no other maturities until 2017.

The restructuring at OPCo has caused a substantial decrease in cash from operations (CFO) in 2014 and management has responded by lowering both the capital investments and dividend payments, we expect to be the norm at OPCo going forward. For 2014, OPCo generated approximately $520 million of CFO, invested $460 million in capital investments and up streamed $35 million in dividend payments to parent AEP, resulting in a positive free cash flow (FCF) of approximately $25 million. In 2013 OPCo generated CFO of approximately $1 billion, invested $670 million in capital investments and up streamed $375 million in dividend payments, resulting in a negative FCF of about $45 million.

AEP's liquidity is adequate. AEP has two syndicated credit facilities totaling $3.5 billion, one is a $1.75 billion facility expiring June 2017, and the other is also a $1.75 billion facility expiring in July 2018. At year-end 2014 AEP had $602 million of commercial paper outstanding and $63 million of letters of credit issued leaving over $2.3 billion of availability on its credit facilities. AEP is not required to make a representation with respect to either material adverse change or material litigation in order to borrow under the facility. Default provisions exclude payment defaults and insolvency/bankruptcy of subsidiaries that are not significant subsidiaries per the SEC definition (in general, this would exclude subsidiaries representing less than 10% of assets or income). The facilities contain a covenant requiring that AEP's consolidated debt to capitalization (as defined) will not exceed 67.5%. AEP states the actual ratio was 51% at year-end 2014, indicating substantial headroom.

Rating Outlook

The stable rating outlook reflects our view that the regulatory environment in Ohio will continue to be supportive,

and that cash flow metrics will stabilize in 2015 and consolidate in the 2016 - 2017 period, such as CFO pre-WC to debt will likely get closer to the twenties, RCF ratio in the mid-teens and debt to book capitalization in mid-forties.

What Could Change the Rating - Up

OPCo could be reviewed for upgrade if deferred costs are recovered in a timely manner and balances pending under the previous ESPs earn a reasonable return, leading to improved financial performance resulting in leverage ratio closer to the twenties and RCF ratio above the mid-teens on a sustainable basis.

What Could Change the Rating - Down

OPCo's ratings could be downgraded if the supportiveness of the regulatory environment changed leading to recovery mechanisms becoming insufficient and/or if there is significant increase in recovery lag. All of which could lead to a prolonged period of financial deterioration such that the CFO pre-WC to debt decreased to the mid-teens, and RCF ratio decline to the low teens range for an extended period of time.

Other Considerations

We acknowledge OPCo's recent business transformation into a low risk regulated T&D and beginning in 2015 have revised our view to reflect this shift, placing OPCo under the low business risk grid within the Regulated Electric and Gas Utilities methodology. That said, it would be unlikely that switching to the low risk business grid would result in any immediate rating upgrades for OPCo.

Rating Factors

OhioPowerCompany

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2015		[3]Moody's 12-18 Month Forward ViewAs of 5/11/2015	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Baa	Baa	Baa	Baa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity		N/A		N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.3x	A	5.3x - 5.8x	A
b) CFO pre-WC / Debt (3 Year Avg)	24.3%	A	19% - 24%	A
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	17.5%	A	13% - 18%	A
d) Debt / Capitalization (3 Year Avg)	42.7%	A	42% - 47%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		Baa1
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-

Financial Corporations. [2] As of 3/31/2015(L); Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on http://www.moodys.com for the most updated credit rating action information and rating history.

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STANDARD & POOR'S RATINGS SERVICES
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Research

Summary:

Ohio Power Co.

Primary Credit Analyst:
Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@standardandpoors.com

Secondary Contact:
Dimitri Nikas, New York (1) 212-438-7807; dimitri.nikas@standardandpoors.com

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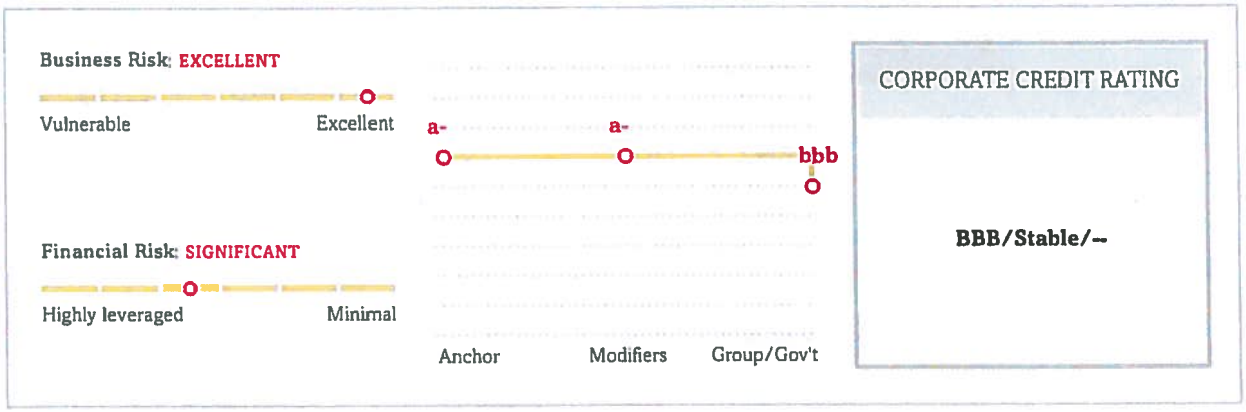
Summary:

Ohio Power Co.



Rationale

Business Risk: Excellent	Financial Risk: Significant
• Regulated transmission and distribution utility that is the sole distributor of essential electricity service in its area • Part of a large electric utility company that is geographically diverse and has a large customer base • Credit-supportive regulation • Transition to full retail choice	• Cash flow erosion from transition to retail choice in Ohio • Large capital expenditures • Strong cash flow measures • Positive free operating cash flow

Outlook: Stable

The stable rating outlook on parent American Electric Power Co. Inc. (AEP) and utility subsidiary Ohio Power Co. reflects Standard & Poor's Ratings Services' expectation that management will focus on its regulated utilities and will not expand unregulated operations beyond the existing level. We expect the company to receive timely cost recovery of rate base investments and operating expenses. The outlook also reflects our expectations that cash flow protection and debt leverage measures will remain at their currently robust levels. Our base-case forecast calls for adjusted funds from operations (FFO) to total debt of about 20%, supplemented by cash flow from operations (CFO) to debt of about 19%. We expect debt to EBITDA to be approximately 4x.

Downside scenario

We could lower the ratings if the business risk profile materially weakened or financial measures fell short of our base-case forecast on a sustained basis, including FFO to total debt falling below 13% or CFO to debt below 11%.

Upside scenario

We could raise the ratings if the business risk profile improves through growth in the utility operations and financial measures remain in line with our base-case forecast. We could also raise the ratings if we maintain our current business risk profile assessment and financial measures strengthen to the "intermediate" financial risk profile category, as defined in our criteria.

Standard & Poor's Base-Case Scenario

Assumptions	Key Metrics
• Economic conditions in the company's service territory are improving, which will likely increase customer usage • EBITDA growth from revenue increases and customer growth is likely to be about the same as it has been in recent years • A retail stability rider allows for recovery of about $500 million throughout the Ohio transition period, ending May 31, 2015 • Capital spending and dividend payouts lead to negative discretionary cash flow, indicating the need for external funding	In our base case, we expect Ohio Power's key adjusted financial measures to approximate historical performance during the next few years. We expect FFO to debt of 18% to 20%, and debt to EBITDA of about 4x, both in line with the "significant" category under our medial volatility benchmarks. We forecast CFO to debt of about 22%, bolstering the "significant" determination. We expect the utility to generate positive free operating cash flow over the next few years. Discretionary cash flow should be negative over the next few years, reflecting capital spending and dividend payments to parent company AEP, indicating external funding needs. Beyond our base-case forecast, we expect to see financial measures that are also similar to our base case measures.

Business Risk: Excellent

Our assessment of Ohio Power's business risk profile as "excellent," as defined in our criteria, is based on the company's "strong" competitive position, "very low" industry risk derived from the regulated utility industry, and the "very low" country risk of the U.S. The competitive position assessment reflects the strengths of an electric utility that provides service from the northwestern part of Ohio to the southeastern part of the state. Now that its generation assets have been transferred to affiliates, the utility is a transmission and distribution electric utility. Ohio Power continues to make the transition to a competitive generation market in which all retail customers shop for generation service. By June 1, 2015, Ohio Power is expected to have fully transitioned to a utility that will hold auctions to provide power to standard-service-offer customers. During the transition, transition costs are being recovered partly through a non-bypassable retail stability rider and partly by recovering from customers the difference between capacity prices set in the PJM market and a capacity price determined by the Public Utilities Commission of Ohio. Any unrecovered capacity deferral is to be accrued and recovered in rates through 2018.

Financial Risk: Significant

Based on the medial volatility financial ratio benchmarks, our assessment of Ohio Power's financial risk profile is "significant." This reflects the recurring cash flow from being a fully regulated transmission and distribution electric utility. Capital spending is necessary for maintenance purposes and new projects. Recovery of costs has generally been adequate. Financial measures over the next few years are expected to remain about the same as existing levels. Discretionary cash flow could change between positive and negative during the forecast period. If negative, it would indicate the need for external funding, and if positive, it would indicate that internal cash flow is adequate to cover capital spending and dividend payments.

Measures could improve if spending is lower than we expect or cost recovery is higher than we expect. Steady cost recovery through the regulatory process will be required to maintain cash flow coverages. For the 12 months ended Dec. 31, 2013, FFO to debt was 38%, CFO to debt was 36%, and debt to EBITDA was 2.1x. However, these ratios include Ohio Power's former generation operations that have been divested to affiliates. Therefore, as a transmission and distribution utility, our baseline forecast reflects financial measures in line with the "significant" determination, such as FFO to debt of 18% to 20% and CFO to debt of 22%.

Liquidity: Adequate

Ohio Power's liquidity reflects that of parent AEP, which we consider "adequate," as our criteria define the term. We believe the company's liquidity sources are likely to cover its uses by more than 1.1x for the next 12 months, and even with a 10% decline in EBITDA.

Large debt maturities are due during the next three years, and we expect the company to refinance these given its satisfactory standing in the credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash on hand of roughly $500 million in 2014 • FFO of roughly $4.2 billion in 2014 • Credit facility availability of about $2.5 billion in 2014 • Working capital of about $350 million in 2014	• Debt maturities of about $1.5 billion in 2014 • Capital spending of about $4.3 billion in 2014 • Dividends of about $970 million in 2014

Other Modifiers

Other modifiers have no effect on the rating outcome.

Group Influence

The stand-alone credit profile of 'a-' for Ohio Power reflects its business and financial risk profiles and is two notches higher than the group credit profile for AEP, which is currently 'bbb'. Under our group rating methodology, we consider Ohio Power a core subsidiary of the AEP group and therefore, the issuer credit rating on Ohio Power is equal to the group credit profile for AEP.

Ratings Score Snapshot

Corporate Credit Rating

BBB/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Financial policy:** Neutral (no impact)
- **Management and governance:** Satisfactory (no impact)

- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb
- **Entity status within group:** Core (-2 notches from SACP)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Stand-Alone Credit Profiles: One Component Of A Rating, Oct. 1, 2010
- Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery, Nov. 10, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008
- 2008 Corporate Criteria: Commercial Paper, April 15, 2008

Business And Financial Risk Matrix

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

Fed's Plosser: Low rates 'should make us nervous'

Katy Barnato | Carolin Roth
Tuesday, 11 Nov 2014 | 4:16 AM ET
CNBC

Interest rates in the U.S. are unprecedentedly low, even allowing forfalling oil prices and "very modest" wage growth, Philadelphia Federal Reserve President Charles Plosser told CNBC on Tuesday, who expressed concern over the low levels.

Plosser, who is one of the Fed's most outspoken "hawks" expressed concern over the low rates. Last month, the Fed confirmed that it would hold the target range for the federal funds rate at 0 to 0.25 percent.

"There are many indicators that tell us interest rates are too low," Plosser told CNBC from the UBS European Conference in London.

"There is no precedented history to have rates at zero. I think we are really behaving in a way which is outside of historical norms and that should make us nervous," he added.

Plosser conceded that "wage growth has been very modest" and that falling oil prices were pressuring short-term inflation lower—but said that rates were too low nonetheless.

"Given the unemployment rate, and even given low inflation, we are below where we would normally be," he said. "I think this is something we should be cognisant of."

Plosser added that the Fed should also avoid responding to short-term fluctuations in either the U.S. dollar or the stock market.

"The dollar is not our responsibility," Plosser told CNBC.

He said the appreciation in the dollar would have "some reverberations", but these would be limited because the U.S. economy was "pretty much closed" when compared to Europe or the U.K.

Plosser is due to retire from the Fed in March next year. He was an economics professor at the University of Rochester before he became the 10th president of the Philly Fed in August 2006.

His retirement will coincide with that of Dallas Fed's Richard Fisher, another central banker who has stridently advocated paring back monetary stimulus.

Plosser and Fisher's departure could change the tenor of debate within the Fed policy-setting committee, giving it a more dovish bent.

"I am sure that a wide range of views will continue to be discussed," Plosser said regarding his retirement, for which he has no immediate plans.

"There will still be a healthy debate I'm sure."

—Writing by CNBC's Katy Barnato; reporting by Carolin Roth

Federal Reserve Statistical Release

H.4.1

Factors Affecting Reserve Balances

Release Date: January 21, 2016

Release dates | Data Download Program (DDP) | About | Announcements | Technical Q&As
Current release *Other formats:* Screen reader | ASCII | PDF (21 KB)

Data Download Program

FEDERAL RESERVE statistical release

H.4.1

Factors Affecting Reserve Balances of Depository Institutions and
Condition Statement of Federal Reserve Banks — January 21, 2016

1. Factors Affecting Reserve Balances of Depository Institutions
Millions of dollars

Reserve Bank credit, related items, and reserve balances of depository institutions at Federal Reserve Banks	Averages of daily figures: Week ended Jan 20, 2016		Change from week ended Jan 13, 2016		Change from week ended Jan 21, 2015	Wednesday Jan 20, 2016
Reserve Bank credit	4,456,214	+	5,284	-	11,467	4,450,281
Securities held outright (1)	4,248,187	+	4,429	+	4,612	4,242,989
U.S. Treasury securities	2,461,412	-	59	+	425	2,461,396
Bills (2)	0		0		0	0
Notes and bonds, nominal (2)	2,346,639		0	-	73	2,346,639
Notes and bonds, inflation-indexed (2)	98,534		0	+	65	98,534
Inflation compensation (3)	16,240	-	58	+	434	16,223
Federal agency debt securities (2)	32,479	-	465	-	5,109	31,318
Mortgage-backed securities (4)	1,754,295	+	4,952	+	9,295	1,750,275
Unamortized premiums on securities held outright (5)	188,844	-	186	-	17,479	188,545
Unamortized discounts on securities held outright (5)	-16,488	+	37	+	1,817	-16,477
Repurchase agreements (6)	0		0		0	0
Loans	85	+	63	-	16	20
Primary credit	70	+	66	-	21	4
Secondary credit	0		0		0	0
Seasonal credit	14	-	4	+	4	16
Other credit extensions	0		0		0	0
Net portfolio holdings of Maiden Lane LLC (7)	1,717		0	+	37	1,717
Float	-129	+	6	+	284	-196
Central bank liquidity swaps (8)	125	+	7	+	115	125
Other Federal Reserve assets (9)	33,873	+	929	-	836	33,558
Foreign currency denominated assets (10)	19,933	+	122	-	599	19,949
Gold stock	11,041		0		0	11,041
Special drawing rights certificate account	5,200		0		0	5,200
Treasury currency outstanding (11)	47,609	+	14	+	1,195	47,609
Total factors supplying reserve funds	4,539,996	+	5,419	-	10,871	4,534,080

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

1. Factors Affecting Reserve Balances of Depository Institutions (continued)
Millions of dollars

Reserve Bank credit, related items, and reserve balances of depository institutions at Federal Reserve Banks	Averages of daily figures: Week ended Jan 20, 2016		Change from week ended Jan 13, 2016		Change from week ended Jan 21, 2015	Wednesday Jan 20, 2016
Currency in circulation (11)	1,414,835	-	2,297	+	84,022	1,414,434
Reverse repurchase agreements (12)	308,626	-	8,533	+	60,400	322,974
Foreign official and international accounts	217,568	-	1,769	+	105,789	216,347
Others	91,058	-	6,764	-	45,389	106,627
Treasury cash holdings	280	+	1	+	74	279
Deposits with F.R. Banks, other than reserve balances	314,189	-	16,951	+	128,829	338,373
Term deposits held by depository institutions	0		0		0	0
U.S. Treasury, General Account	285,318	-	17,665	+	115,166	318,749
Foreign official	5,288	+	44	+	67	5,231
Other (13)	23,584	+	671	+	13,597	14,393
Other liabilities and capital (14)	47,296	+	328	-	16,575	45,942
Total factors, other than reserve balances, absorbing reserve funds	2,085,226	-	27,452	+	256,751	2,122,002
Reserve balances with Federal Reserve Banks	2,454,769	+	32,870	-	267,623	2,412,078

Note: Components may not sum to totals because of rounding.

1. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.
2. Face value of the securities.
3. Compensation that adjusts for the effect of inflation on the original face value of inflation-indexed securities.
4. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
5. Reflects the premium or discount, which is the difference between the purchase price and the face value of the securities that has not been amortized. For U.S. Treasury and Federal agency debt securities, amortization is on a straight-line basis. For mortgage-backed securities, amortization is on an

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PERSPECTIVES

Prospects for and Ramifications of the Great Central Banking Unwind

William Poole

At the CFA Institute Global Investment Risk Symposium held in Washington, DC, on 7–8 March 2013, William Poole gave a presentation on what he calls the "great central banking unwind." Total assets on the balance sheets of the U.S. Federal Reserve and European Central Bank have exploded since 2008. The challenges and pressure faced by these and other central banks will probably have serious consequences for the global economy.

I am very uneasy about the current economic and fiscal situation in the United States and Europe. The central bank policies and fiscal disequilibrium in these countries are unlike any circumstances they have endured in the past; it is uncertain how the massive easing of the last five years is going to affect the developed nations' economies as well as the global economy. The world is in uncharted territory.

I am going to focus on the U.S. Federal Reserve System and the European Central Bank (ECB). The Fed is the most important central bank in the world: Without stability in the United States, the world economy will not have stability. Not only must central banks navigate the challenges presented by slower growth and fiscal deficits, but they also face powerful political pressures that, if succumbed to, may have harmful consequences domestically and globally.

Fed Issues vs. ECB Issues

Although both the United States and the eurozone had significant economic downturns and financial disruption during the financial crisis, the Fed's expansionary monetary policy has been motivated primarily by a concern over unemployment whereas the ECB's policy has been motivated by an effort to support the sovereign debt of fiscally weak governments—in particular, the southern European countries.

Figure 1 shows the Fed's balance sheet assets from 2007 to 2013. Before the financial crisis, its assets were around $850 billion; they have now risen to nearly $3 trillion, and the Fed keeps pumping money into the system. It is unclear when the Fed's policy of easing is going to stop or how it is going to be reversed.

But the Fed is not alone. The ECB has been pumping funds into the European markets, as shown in **Figure 2**. Total assets on the ECB's balance sheet have increased from about €1.2 trillion in 2007 to about €3 trillion in the first quarter of 2013. The Bank of England (BOE) and a number of other central banks have been following suit. A massive monetary expansion has taken place over the last five years.

The ECB is acting as a lifeboat for sinking public finances after a collision of high levels of entitlement spending and sustained low economic growth. The plight of Greece in 2012 has led the way; other nations, Italy prominent among them, will most certainly follow. Greece was unable to raise needed funds by issuing sovereign debt after December 2008 because investors would no longer buy it; the risk of default was too high.

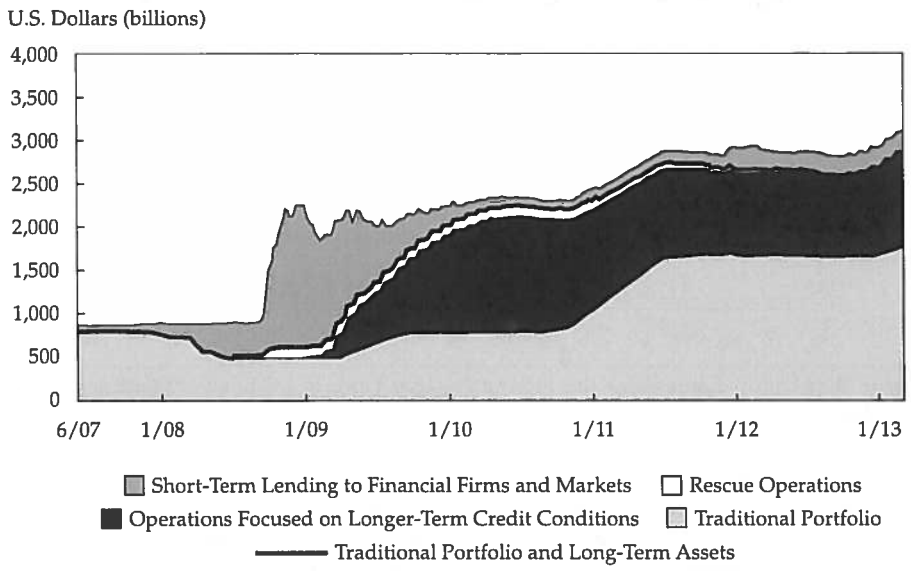
Great Fed Unwind

Given the very large buildup of assets on its balance sheet, it might appear that the Fed has to unwind the position, but that is not necessarily the case. The Fed might keep a very large portfolio indefinitely.

Reserve Ratio. The monetary mechanism that the Fed, or any central bank, uses to control the growth of money and credit is completely different from what it was in the past. The Fed's main instrument of controlling money and credit growth in the past was the reserve requirement, which sets

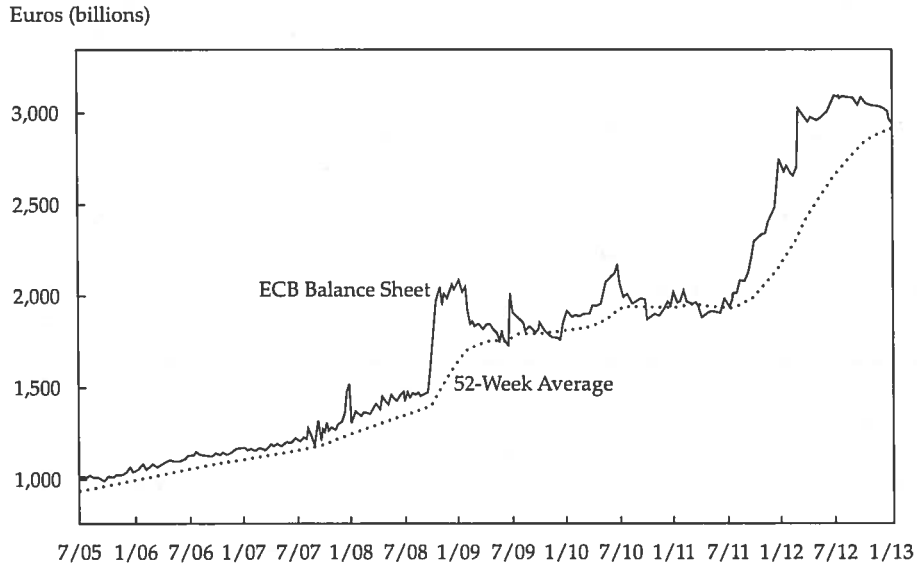
William Poole is a senior fellow at the Cato Institute, Washington, DC.

Figure 1. U.S. Federal Reserve Balance Sheet Assets, June 2007–February 2013



Source: Based on a figure from the Federal Reserve Bank of St. Louis, "U.S. Financial Data" (22 February 2013):7.

Figure 2. ECB Balance Sheet Assets, 2005–2013



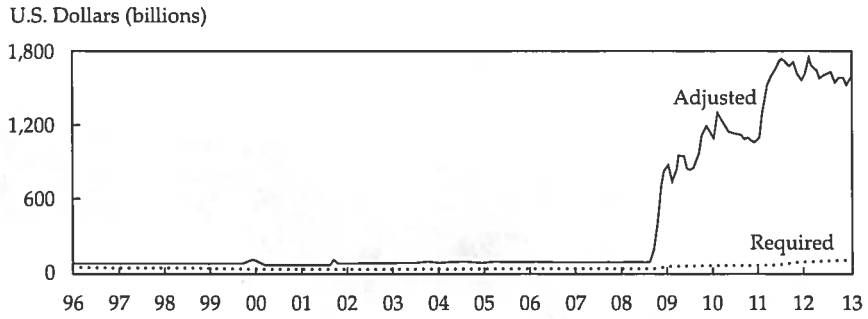
Sources: Based on data from Gold Silver Worlds and Weldon Financial.

forth the amount of reserves that banks had to keep on deposit with the Fed. The amount of a bank's deposits with the Fed is a percentage of its total demand deposits.

Today, banks are no longer constrained by the reserve ratio. In the past, the Fed had no authority to pay interest on bank reserves, so banks typically held only the minimum amount of reserves required. But in 2008, new legislation gave the Fed the authority to pay interest on reserves, which the Fed has currently set at the rate of 0.25%. That rate is above other money market rates and thus has provided an incentive for banks to increase their excess reserves at the Fed.

Figure 3 shows the dramatic increase in bank reserves since mid-2008; as of 20 February 2013, they are now more than $1.5 trillion. Given the latest round of quantitative easing (QE) by the Federal Reserve, these bank reserves will continue to grow. The dotted line in Figure 3 represents the amount of required reserves, which contrasts markedly with the enormous stockpile of excess reserves sitting

Figure 3. Adjusted and Required Federal Reserves, January 1996–February 2013



Source: Based on a figure from the Federal Reserve Bank of St. Louis, "Monetary Trends" (26 February 2013):6.

on bank balance sheets. Banks are holding these reserves rather than lending them or buying assets with them because the Fed is paying interest on them. Reserves are the raw material for a money and credit expansion, but this raw material is not being actively used. To date, money and credit growth has been moderate. There are no signs of overheating, and the same is true for inflation expectations.

Two measures of the money supply—money zero maturity (MZM) and M2—are plotted in **Figure 4** from 1996 through mid-February 2013. M2 is calculated as M1 (all physical money, such as coins and currency, plus demand deposits, or checking accounts, and Negotiable Order of Withdrawal accounts) plus time deposits, savings deposits, and noninstitutional money market funds. MZM is defined as the liquid money supply in an economy—all assets convertible to cash on demand without penalty. The bigger area of shading at the right is the most recent recession, drawn from the cycle peak in December 2007 to the cycle trough in June 2009. The smaller area of shading on the left represents the much milder recession in 2001. Money stock growth measured by both definitions has recently been well within the normal range.

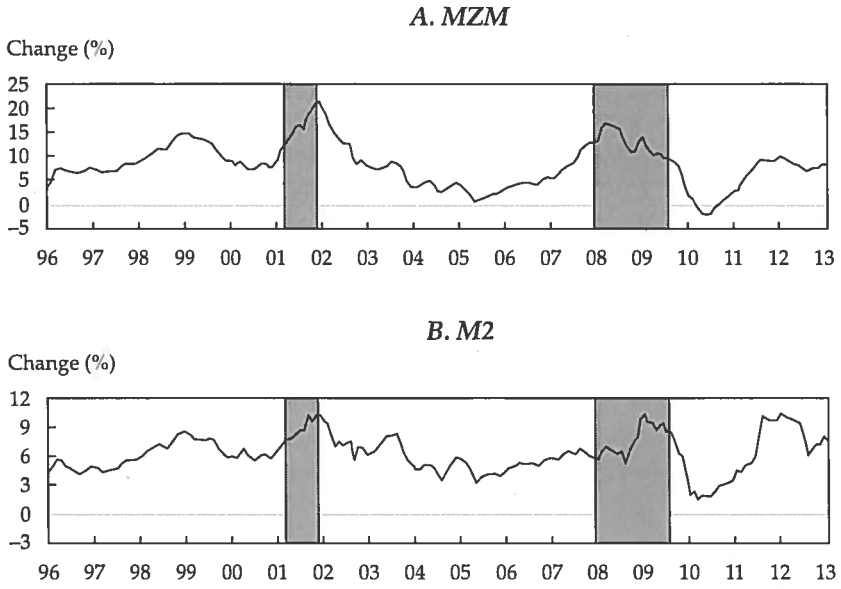
Inflation expectations can be measured in a number of ways, but I prefer a market-based measure to a survey measure. A market-based measure is derived from the spread between inflation-indexed Treasury bonds and conventional bonds. **Figure 5** compares yields in percentage terms for three different maturities: 5, 10, and 30 years. The spread between the conventional and indexed bonds stays in a relatively tight range from December 2011 to February 2013, and the spreads at the 10-year mark are in the same range they have been in for the past 10–12 years.

Raising the Federal Funds Rate. If inflation starts to rise, the Federal Reserve's standard strategy is to raise its target for the federal funds rate, which is the interest rate on interbank lending and borrowing. Federal funds are nothing more than bank reserves; banks are able to lend the reserve balances they have on account at the Fed. Now that the Fed pays interest on bank reserves, the interest rate on bank reserves is tied, almost to the basis point, to the federal funds rate. The Fed cannot raise the federal funds rate without also raising the rate that it pays on bank reserves, and at some point, the rate increases must be large enough to persuade banks to hold reserves rather than engage in an excessive expansion of money and credit that would create an inflation problem.

Despite all of the progress the financial industry has made in terms of modeling and statistical technology, the Fed basically decides how much to raise the federal funds rate in the same manner that a driver attempts to hold a steady speed when driving in mountainous territory. If the car is going too fast down the mountain, the driver eases up on the accelerator. If that action isn't enough, the driver eases up more and maybe taps the brakes. Likewise, the Fed reduces its assets to drive up interest rates, but the required pace of reduction is not clear *ex ante*. The basic idea is simple: If the economy is growing too fast, the Fed taps on the monetary policy brake by increasing interest rates. The Fed then adjusts its policy based on feedback and observation of recent data.

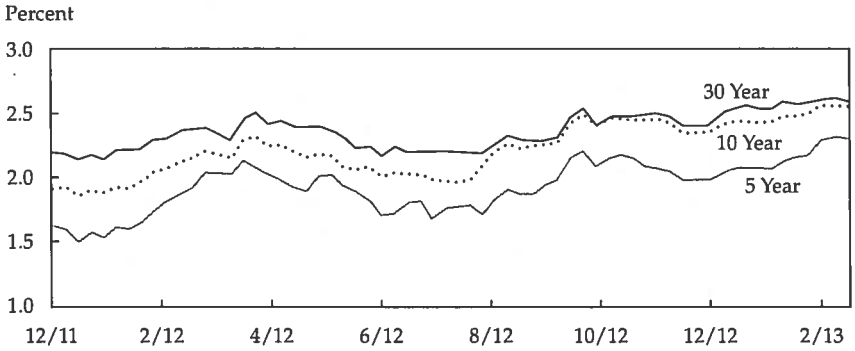
Forecasts. Everyone who deals with portfolio management knows that an action taken in response to a problem depends on the decision maker's belief about a forecast. And when making decisions, it is easy to be in denial about the most recent information. Likewise, if the Fed starts to see inflation while the unemployment rate is still high, it may choose to deny reality and take the position that the inflation bump is a temporary aberration, perhaps related to energy prices or some other issue.

Figure 4. Change in Two Measures of the Money Supply, January 1996–February 2013



Note: Change is the percentage change from one year ago.
Source: Based on a figure from the Federal Reserve Bank of St. Louis, "Monetary Trends" (26 February 2013):4.

Figure 5. Inflation-Indexed Treasury Yield Spreads, December 2011–February 2013



Note: Data represent averages of daily figures.
Source: Based on a figure from the Federal Reserve Bank of St. Louis, "U.S. Financial Data" (22 February 2013):12.

Such inaction on the part of the Federal Reserve might be motivated by a desire to avoid tightening policy too soon because of an overriding interest in and responsibility for advancing the rate of employment growth. But if the Fed is in denial too long, inflation can become embedded in the economy. One of the best examples of Fed inflation denial is illustrated by monetary policy from roughly 1965 to 1979; Paul Volcker took over as chairman of the Fed in August 1979 to deal with the inflation. After 1965, the Fed was concerned that tighter policy would choke off employment growth, so it allowed inflation to creep up and up until the creep became a gallop.

Political Pressure. The Fed is also likely to face political pressure to raise rates only slowly. Federal Reserve chairman Ben Bernanke talks a lot about risk management and the tradeoff between benefits and costs; he maintains that the need to balance these two issues justifies proceeding with the current policy. But Bernanke does not discuss the risk of political intervention in Fed policy despite numerous examples of the Fed giving in to political pressure and waiting too long to change its policy, which results in a detrimental outcome for the economy.

Mortgage finance interests have been extremely well organized politically and are quite influential.

Part of the Fed's QE policy is to buy $40 billion of mortgage-backed securities (MBSs) a month. Stopping that part of its expansionary policy—without even considering unwinding the portfolio—will produce a lot of political pushback. This pushback will come through the housing and mortgage interests, through representatives in Congress, and perhaps through the president. Essentially, pressure on the Fed will come from inside the government and may not be very visible; it may be limited to a few op-ed articles from the housing lobby. The true amount of political pressure will largely be hidden.

Pressure to keep rates low will come also from those who argue that the Fed should do its share to hold down the federal budget deficit. Higher interest rates will produce a rapid and enormous increase in the interest expense in the federal budget. The Fed is going to be encouraged to suppress interest rates until longer-run reforms can be put in place to address the budget deficit.

Recent discussion has centered on the impact of Fed policy on a number of issues. For example, is Fed policy creating a bubble in the bond or stock markets or in farmland prices? Is Fed policy pushing down the dollar exchange rate? Bubbles are easy to understand after the fact but very difficult to identify in real time. Many market fluctuations were thought to be unsustainable at the time but turned out to be justified by fundamentals. So, Fed policy may or may not be bubble inducing. But the real issue is the politics of monetary policy.

I believe that the Fed will not successfully resist the political winds that buffet it. I am not a political expert or a political analyst by trade. My qualification for speaking on this topic is that I have followed the interactions between monetary policy and politics for a very long time. As with all things political, the politics of the Fed means that realities often fail to match outward appearances.

I believe the Fed is likely to overdo its current QE policy of purchasing $45 billion of Treasuries and $40 billion of MBSs per month. Turning off the spigot would be difficult, but to be effective, the Fed has to stop its expansionary policy before inflation becomes embedded in the economy. For policy to be effective, it needs to be preemptive. Inflation control is better when accomplished before inflation has risen, not after.

Uncertainties. Although forecasts always contain uncertainties, the federal budget and regulatory uncertainties today are greater than at any time over the past 60 years. These budget and regulatory uncertainties are the prime explanation for the slowness of the economic recovery; businesses are hanging back until they better understand, or think they better understand, the way that the regulations are going to be written and interpreted. The load of regulations on the business sector is larger than it has been since the 1930s: the Affordable Care Act and the Dodd–Frank Wall Street Reform and Consumer Protection Act, as well as the policies of the Environmental Protection Agency and the Department of Labor. I think President Obama and his administration—in large part because they do not understand the markets as well as they might—will not hesitate to pressure the Fed, initially from the inside and perhaps ultimately from the outside by encouraging heavy public criticism once the Fed embarks on a policy of raising rates. Such an approach will likely be counterproductive, and the markets will respond very negatively.

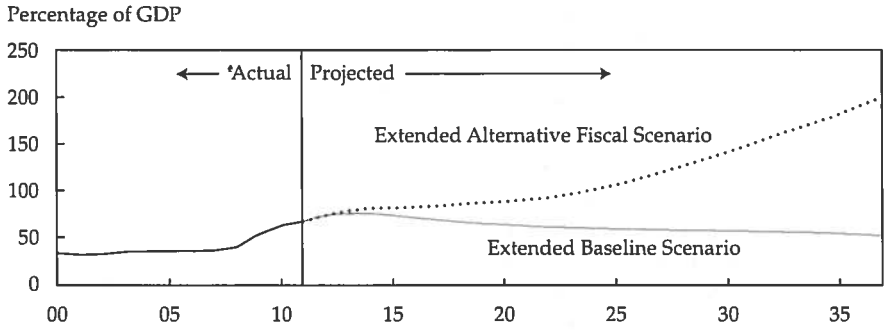
The very deep fiscal disequilibrium in the United States is best understood by looking at the data from the Congressional Budget Office (CBO). The budget games that are played with the numbers are full of screwy and misleading accounting. For example, the alternative minimum tax (AMT) was patched one year at a time so that the forward projections of revenues from the AMT would be in all the official projections of the budget. But the patchwork nature of the process created uncertainty about its final structure. Another example on the expenditure side is from more than 10 years ago: Since the Clinton years, legislation on the books has called for large reductions in Medicare reimbursements to physicians. The "doc fix" was enacted one year at a time so that the physicians would not have their reimbursements cut by a third. The budget encompassed forward projections of outlays that were lower than the outlays that would actually occur.

Figure 6 shows the federal debt forecast under two CBO long-term budget scenarios as of June 2012. This forecast is updated each summer. The dotted line shows the projected debt level over the next 25 years without the kind of budget gimmicks I just described. The shaded line shows the debt-level projection with all the budget gimmicks included. The United States is in the process of struggling with this enormous disequilibrium, although its struggle so far has been about the discretionary part of the budget, without any very serious political discussion—let alone legislative proposals—related to Social Security and Medicare expenditures, which are driving the budget. Until entitlement outlays are addressed, the budget is going to look more like the dotted line in Figure 6 than the shaded line.

Great ECB Unwind

The ECB has acquired a substantial amount of the sovereign debt of the fiscally weak southern European countries. It has also been lending to banks that have, in turn, purchased the debt of the weak

Figure 6. Federal Debt Forecast under the CBO's Long-Term Budget Scenarios, 2000–2037



Note: Forecast is as of June 2012.
Source: Based on a figure from the Congressional Budget Office, "The 2012 Long-Term Budget Outlook" (5 June 2012):2.

countries. The European banking regulations have so-called risk-weighted capital requirements, but the risk weight on all sovereign debt is zero. So, a bank can buy the bonds of Italy or Spain or even Greece and have a zero capital requirement. Obviously, the capital requirements are not truly risk weighted; they are politically weighted. The capital requirements in Europe, as in the United States, are deeply affected by the politics of bank regulation.

The situation in Europe is still very much in flux. Italy recently had a very indecisive election. The citizens of the weak nations are not embracing the austerity that is required to bring their economies back in line. They want to keep their benefits, and they do not want to pay taxes. These desires are perfectly rational but are not conducive to fiscal sustainability. So, the crisis that has long been predicted—because of much larger welfare state commitments than can be financed with an aging and retired population—has finally arrived and is by no means resolved.

The ECB cannot unwind the assets it owns unless Spain, Italy, Portugal, and Greece resolve their fiscal problems. Thus, these countries' debt might remain on the ECB's balance sheet—and the loans to these countries on European banks' balance sheets—for some time. Therefore, if Europe begins to have an inflation problem, the ECB will have its hands tied to a significant extent and will be limited in its ability to deal with rising inflation.

Europe is afraid of contagion, in which a default in one country results in investors fleeing the bond markets of the other fiscally weak countries. Thus, the weak countries remain supported by the fiscally sound countries—essentially, Germany—but Germany does not have the resources to support the weak countries indefinitely.

The ECB's charter was supposed to protect it from this situation, but the ECB has caved in to the pressure. To date, there is no evidence of inflationary problems in Europe, at least on the continent, although the United Kingdom has experienced some inflation.

It is a close call in Europe, but I believe that the fundamental fiscal weakness in Europe will end in a crisis. The European community encompasses overextended welfare states, many of which, particularly in southern Europe, have weak administration of tax law and negative politics on decreasing outlays. Many of its public enterprises are inefficient, and its labor markets are burdened by structural rigidities.

The consequences of poor fundamentals in Europe are negative economic growth and rising unemployment. It remains an open question whether Germany's voters will ultimately say that they will no longer support Italy, Spain, Portugal, and Greece. The Merkel administration has retained the support of the German people so far, but without any improvement in the situation, the time may come when Germany's voters ask themselves why they should pay for the excesses of others.

Conclusion

Because no precedents exist for the massive monetary easing that has been practiced over the past five years in the United States and Europe, the uncertainty surrounding the outcome of central bank policy is also vast. So far, inflationary pressures remain subdued, but the ability and willingness of the Fed and the ECB to react quickly to control inflation fears are in jeopardy, largely because of political forces. Total assets on the balance sheets of most developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.

This article qualifies for 0.5 CE credit.

Question and Answer Session

William Poole

Question: Is the dual mandate of maximum employment and price stability a burden on Fed policy?

Poole: The dual mandate is not necessarily a problem. The 1977 law stated that the Fed is supposed to work toward two objectives: inflation and employment. In January 2012, the Federal Open Market Committee (FOMC) set forth the principles with which it approaches its dual mandate. At that time, the FOMC adopted an inflation target of 2%, and the target was renewed in January 2013. The published principles state that no central bank can promise to create a certain level of employment growth or a certain level of unemployment because those are real variables that are controlled by the real conditions in the economy, including such conditions as fiscal policy, and are ultimately not the responsibility of Fed policy.

Question: What is the primary weakness of the Fed?

Poole: I fault the Fed for its lack of intellectual leadership on the economy and, in particular, Bernanke's lack of forthrightness about the limits of the Fed's ability to address slow growth and fiscal disequilibrium. Most of the Federal Reserve bank presidents (with the exceptions of Charles Plosser in Philadelphia, Richard Fisher in Dallas, Jeffrey Lacker in Richmond, and to some extent, my successor in St. Louis, Jim Bullard) have been essentially silent on this issue, speaking only in vague terms about the necessity for fiscal stability and not identifying the uncertainty over that issue as a reason for the slow economic expansion.

Question: Is the Fed structured for failure?

Poole: That question is very important. Institutions need to be considered separately from the individuals who inhabit them. If certain individuals are going to make a mess of something, no institutional structure can guard against that except through a system of checks and balances. Past research has shown that central bank independence produces a better result than monetary policy run by the Treasury. Independence for the Federal Reserve began 100 years ago, when the Federal Reserve Act was signed in December 1913. The Fed's structure provides substantial independence, allowing room for strong leadership to do what has to be done in the face of adverse political pressure. The Fed's structure does not guarantee independence, but it provides the room. Paul Volcker has made significant use of that independence, whereas Arthur Burns, one of the architects of monetary policy and the inflation that culminated from it, did not. No institutional structure can guarantee a good result, but institutional structures can allow strong people to fail because they lose control.

Question: If the Fed were to adopt the equivalent of a Taylor rule today,[1] what should it be?

Poole: A simple Taylor-like rule that relates to only a couple of variables when so much is going on is unworkable at this point. An appropriate goal might be to have a central bank that is more constrained by legislative rules, but I just do not see a workable rule at this time.

Question: What is your opinion about returning to the gold standard?

Poole: I think the gold standard is unworkable. It was not as satisfactory in the 19th century, during its heyday, as is often argued. The basic problem is easy to see. When there is a flight to liquidity, when the market wants more gold, there is no more gold. The supply is fixed. All sorts of liabilities backed by gold have been issued, but those liabilities far exceed the gold supply. Therefore, the gold standard is a recipe for a banking system that collapses under stress, although it did stabilize the price level over a long period of time.

Notes

1. A Taylor rule is a monetary policy rule that stipulates how much the central bank should change the nominal interest rate in response to changes in inflation, output, or other economic conditions.

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Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. The Value Line data are commercially available on a timely basis to investors in paper format or electronically. Value Line betas are derived from a least-squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the New York Stock Exchange Average over a period of 5 years. In the case of shorter price histories, a smaller time period is used, but 2 years is the minimum. Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00. This necessary adjustment to beta is discussed below.

Practical and Conceptual Difficulties

Computational Issues. Absolute estimates of beta may vary over a wide range when different computational methods are used. The return data, the time period used, its duration, the choice of market index, and whether annual, monthly, or weekly return figures are used will influence the final result.

Ideally, the returns should be total returns, that is, dividends and capital gains. In practice, beta estimates are relatively unaffected if dividends are excluded. Theoretically, market returns should be expressed in terms of total returns on a portfolio of all risky assets. In practice, a broadly based value-weighted market index is used. For example, Merrill Lynch betas use the Standard & Poor's 500 market index, while Value Line betas use the New York Stock Exchange Composite market index. In theory, unless the market index used is the true market index, fully diversified to include all securities in their proportion outstanding, the beta estimate obtained is potentially distorted. Failure to include bonds, Treasury bills, real estate, etc., could lead to a biased beta estimate. But if beta is used as a relative risk ranking device, choice of the market index may not alter the relative rankings of security risk significantly.

To enhance statistical significance, beta should be calculated with return data going as far back as possible. But the company's risk may have changed if the historical period is too long. Weighting the data for this tendency is one possible remedy, but this procedure presupposes some knowledge of how risk changed over time. A frequent compromise is to use a 5-year period with either weekly or monthly returns. Value Line betas are computed based on weekly returns over a 5-year period, whereas Merrill Lynch betas are computed with monthly returns over a 5-year period. In an empirical study of utility

THE COST OF CAPITAL TO A PUBLIC UTILITY

Myron J. Gordon

1974
MSU Public Utilities Studies

Division of Research
Graduate School of Business Administration
Michigan State University
East Lansing, Michigan

so that the current value can be widely off the mark as a measure of the expected future value.

5.4 *Other Measures of Growth*

The measure of expected growth in the dividend established in the previous two sections, the intrinsic growth rate, is not the only possible measure of the variable. Another plausible measure is some average of the past rates of growth in the dividend. Under our model of security valuation, dividend, earnings, and price per share all are expected to grow at the same rate. Hence, the rates of growth in the dividend, earnings, and price also are candidates for estimates of the expected rate of growth in the dividend.

Let us consider first the rate of growth in earnings per share. The earnings per share during T adjusted for stock splits and stock dividends to make interperiod comparisons valid is

$$\text{AYPS}(T) = \text{AFC}(T)/.5\,[\text{ANS}(T) + \text{ANS}(T-1)], \qquad (5.4.1)$$

where ANS(T) is the number of shares outstanding at the end of T adjusted for stock splits and dividends. The rate of growth in earnings per share during T is

$$\text{YGR}(T) = [\text{AYPS}(T) - \text{AYPS}(T-1)]/\text{AYPS}(T-1). \qquad (5.4.2)$$

For reasons to be given shortly, the smoothed rate of growth in earnings is superior to the current rate as a forecast of the expected rate. The smoothed rate of earnings growth is obtained from

$$Ln[1 + \text{YGRS}(T)] = \lambda Ln[1 + \text{YGR}(T)] + (1-\lambda)Ln[1 + \text{YGRS}(T-1)], \qquad (5.4.3)$$

with $\lambda = .15$ and YGRS(1953) = .04.

The primary reason for a difference between YGR and GRTH is a change in the rate of return on the common equity. To illustrate, assume a firm that has been earning a return on common of .10 and retaining one-half of its income to finance its investment. The rate of growth under both measures will be .05. If the firm's rate

of return on common rises from .10 to .11, the retention growth rate will rise from .05 to (.5)(.11) = .055. However, the earnings growth rate will rise from .05 to .155.[5] Furthermore, the earnings growth rate in subsequent periods will be .055 if the return on common remains .11. This example suggests that the intrinsic growth rate is superior to the earnings growth rate as a measure of expected growth. Investors nonetheless may look to past data on earnings growth for information on expected future growth, and it is the growth investors expect that should be used to measure share yield.

A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth. First, the intrinsic growth rate includes stock financing growth as well as retention growth. The former is difficult for us to measure and may be even more difficult for investors. Consequently, investors may use past earnings growth to forecast the future since it incorporates in one statistic growth from all sources. Second, we saw that inflation will result in a rise in the allowed rate of return on equity for a regulated company. If this response to inflation takes place with a lag, that is, the regulatory agency raises RRC over time, earnings growth will reflect the forecast rate of growth better than intrinsic growth. Finally, it appears that security analysts use past growth in earnings more than any other variable to forecast future growth.

Given that earnings growth is used by investors to forecast future growth, the smoothed value of the variable YGRS is superior to the current value. The previous illustration revealed that YGR overreacts to changes in the allowed rate of return and therefore is subject to large random fluctuations. The data on YGR confirm this conclusion.

The use of dividend growth as a forecast of future growth is subject to the same limitations as earnings if the firm pays a constant fraction of its earnings in dividends. That is, under this assumption the dividend growth rate in any period is the same as the earnings growth rate. Firms tend to change their dividend rate from one

[5] Let the book value per share at the start of T be BVS($T-1$) = \$50.00. With RRC(T) = .10, AYP(T) = \$5.00, and with RETR(T) = .5, BVS(T) = \$52.50. If RRC($T+1$) = .10, AYP($T+1$) = \$5.25, and YGR($T+1$) = RTGR($T-1$) = .05. However, if RRC($T+1$) = .11, RTGR($T+1$) = (.11)(.5) = .055, while AYP($T+1$) = \$5.775, and YGR($T+1$) = (\$5.775 − \$5.00)/\$5.00 = .155.

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The average growth rate estimate from all the analysts that follow the company measures the consensus expectation of the investment community for that company. In most cases, it is necessary to use earnings forecasts rather than dividend forecasts due to the extreme scarcity of dividend forecasts compared to the widespread availability of earnings forecasts. Given the paucity and variability of dividend forecasts, using the latter would produce unreliable DCF results. In any event, the use of the DCF model prospectively assumes constant growth in both earnings and dividends. Moreover, as discussed below, there is an abundance of empirical research that shows the validity and superiority of earnings forecasts relative to historical estimates when estimating the cost of capital.

The uniformity of growth projections is a test of whether they are typical of the market as a whole. If, for example, 10 out of 15 analysts forecast growth in the 7%–9% range, the probability is high that their analysis reflects a degree of consensus in the market as a whole. As a side note, the lack of uniformity in growth projections is a reasonable indicator of higher risk. Chapter 3 alluded to divergence of opinion amongst analysts as a valid risk indicator.

Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of g. The accuracy of these forecasts in the sense of whether they turn out to be correct is not at issue here, as long as they reflect widely held expectations. As long as the forecasts are typical and/or influential in that they are consistent with current stock price levels, they are relevant. The use of analysts' forecasts in the DCF model is sometimes denounced on the grounds that it is difficult to forecast earnings and dividends for only one year, let alone for longer time periods. This objection is unfounded, however, because it is present investor expectations that are being priced; it is the consensus forecast that is embedded in price and therefore in required return, and not the future as it will turn out to be.

Empirical Literature on Earnings Forecasts

Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data only.

Academic research confirms the superiority of analysts' earnings forecasts over univariate time-series forecasts that rely on history. This latter category

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mendation that is different than the expected ROE that the method assumes the utility will earn forever. For example, using an expected return on equity of 11% to determine the growth rate and using the growth rate to recommend a return on equity of 9% is inconsistent. It is not reasonable to assume that this regulated utility company is expected to earn 11% forever, but recommend a 9% return on equity. The only way this utility can earn 11% is that rates be set by the regulator so that the utility will in fact earn 11%. One is assuming, in effect, that the company will earn a return rate exceeding the recommended cost of equity forever, but then one is recommending that a different rate be granted by the regulator. In essence, using an ROE in the sustainable growth formula that differs from the final estimated cost of equity is asking the regulator to adopt two different returns.

The circularity problem is somewhat dampened by the self-correcting nature of the DCF model. If a high equity return is granted, the stock price will increase in response to the unanticipated favorable return allowance, lowering the dividend yield component of market return in compensation for the high g induced by the high allowed return. At the next regulatory hearing, more conservative forecasts of r would prevail. The impact on the dual components of the DCF formula, yield and growth, are at least partially offsetting.

Third, the empirical finance literature discussed earlier demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock price and price/earnings ratios, as other historical growth measures or analysts' growth forecasts. Other proxies for growth, such as historical growth rates and analysts' growth forecasts, outperform retention growth estimates. See for example Timme and Eiseman (1989).

In summary, there are three proxies for the expected growth component of the DCF model: historical growth rates, analysts' forecasts, and the sustainable growth method. Criteria in choosing among the three proxies should include ease of use, ease of understanding, theoretical and mathematical correctness, and empirical validation. The latter two are crucial. The method should be logically valid and consistent, and should possess an adequate track record in predicting and explaining security value. The retention growth method is the weakest of the three proxies on both conceptual and empirical grounds. The research in this area has shown that the first two growth proxies do a better job of explaining variations in market valuation (M/B and P/E ratios) and are more highly correlated to measures of value than is the retention growth proxy.

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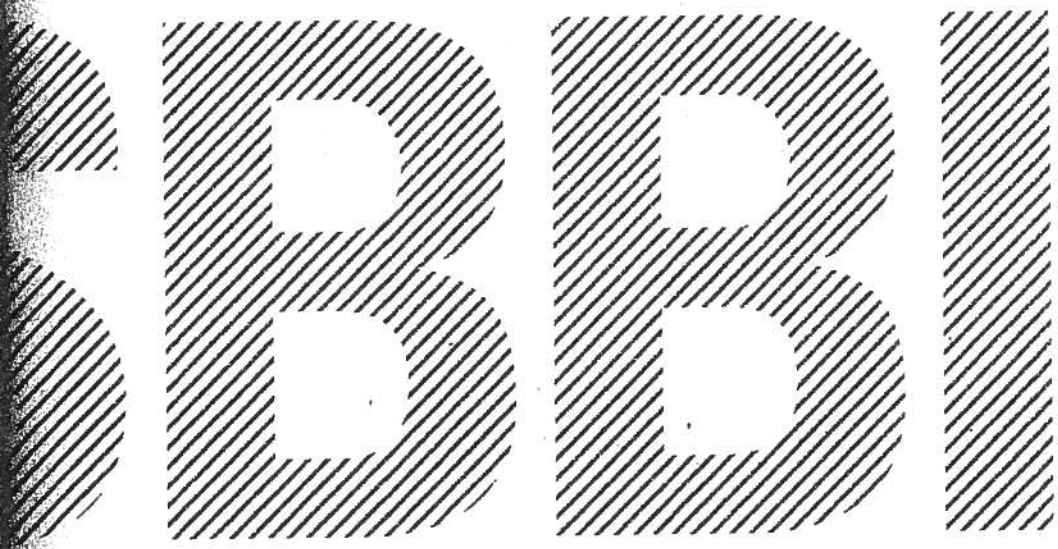

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Chapter 7

Company Size and Return

One of the most remarkable discoveries of modern finance is the finding of a relationship between company size and return.[1] Historically on average, small companies have higher returns than those of large ones. Earlier chapters of this book document this phenomenon for the smallest stocks on the New York Stock Exchange, or NYSE. The relationship between company size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks. This chapter examines returns across the entire range of company size.

Construction of the Size Decile Portfolios

The portfolios used in this chapter are those created by the Center for Research in Security Prices, or CRSP, at the University of Chicago's Booth School of Business. CRSP has refined the methodology of creating size-based portfolios and has applied this methodology to the entire universe of NYSE/AMEX/NASDAQ-listed securities going back to 1926.

The NYSE universe excludes closed-end mutual funds, preferred stocks, real estate investment trusts, foreign stocks, American Depository Receipts, unit investment trusts, and Americus Trusts. All companies on the NYSE are ranked by the combined market capitalization of all their eligible equity securities. The companies are then split into 10 equally populated groups or deciles. Eligible companies traded on the NYSE, the NYSE MKT LLC (formerly known as the American Stock Exchange, or AMEX), and the NASDAQ Stock Market (formerly the NASDAQ National Market) are then assigned to the appropriate deciles according to their capitalization in relation to the NYSE breakpoints. The portfolios are rebalanced using closing prices for the last trading day of March, June, September, and December. Securities added during the quarter are assigned to the appropriate portfolio when two consecutive month-end prices are available. If the final NYSE price of a security that becomes delisted is a month-end price, then that month's return is included in the quarterly return of the portfolio. When a month-end NYSE price is missing, the month-end value is derived from merger terms, quotations on regional exchanges, and other sources. If a month-end value is not available, the last available daily price is used.

In October 2008, NYSE Euronext acquired the American Stock Exchange and rebranded the index as NYSE Amex. Later, in May 2012, it was renamed NYSE MKT LLC. For the sake of continuity, we refer to this index as AMEX, its historical name.

Base security returns are monthly holding period returns. All distributions are added to the month-end prices. Appropriate adjustments are made to prices to account for stock splits and dividends. The return on a portfolio for one month is calculated as the value weighted average of the returns for the individual stocks in the portfolio. Annual portfolio returns are calculated by compounding the monthly portfolio returns.

Aspects of the Company Size Effect

The company size phenomenon is remarkable in several ways. First, the greater risk of small-cap does not, in the context of the capital asset pricing model, fully account for their higher returns over the long term. In the CAPM only systematic, or beta risk, is rewarded; small-cap stock returns have exceeded those implied by their betas.

Second, the calendar annual return differences between small- and large-cap companies are serially correlated. This suggests that past annual returns may be of some value in predicting future annual returns. Such serial correlation, or autocorrelation, is practically unknown in the market for large-cap stocks and in most other equity markets but is evident in the size premium series.

Table 7-5: Size-Decile Portfolios of the NYSE/AMEX/NASDAQ Number of Companies, Historical and Recent Market Capitalization

Decile	Historical Average Percentage of Total Capitalization	Recent Number of Companies	Recent Decile Market Capitalization (in Thousands)	Recent Percentage of Total Capitalization
1-Largest	64.03%	185	14,808,784,274	64.25%
2	14.04	199	3,247,447,914	14.09
3	6.88	194	1,579,432,904	6.85
4	4.56	221	1,042,428,212	4.52
5	3.03	215	694,147,086	3.01
6	2.56	265	585,657,120	2.54
7	1.99	317	449,325,255	1.95
8	1.51	417	333,731,801	1.45
9	0.80	395	173,673,205	0.75
10-Smallest	0.61	948	135,401,288	0.59
Mid-Cap 3-5	14.47	630	3,316,008,202	14.39
Low-Cap 6-8	6.05	999	1,368,714,176	5.94
Micro-Cap 9-10	1.41	1,343	309,074,493	1.34

Data from 1926–2014. Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2015 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

Historical average percentage of total capitalization shows the average, over the last 89 years, of the decile market values as a percentage of the total NYSE/AMEX/NASDAQ calculated each month. Number of companies in deciles, recent market capitalization of deciles, and recent percentage of total capitalization are as of Sept. 30, 2014.

Decile	Recent Market Capitalization (in Thousands)	Company Name
1-Largest	$591,015,721	Apple Inc
2	24,272,837	Cummins Inc
3	10,105,622	Murphy Oil Corp
4	5,844,592	Alaska Airgroup Inc
5	3,724,186	Great Plains Energy Inc
6	2,542,913	Wolverine World Wide Inc
7	1,686,860	Wesco Aircraft Holdings Inc
8	1,010,634	First Bancorp P R
9	548,839	G P Strategies Corp
10-Smallest	300,725	M V Oil Trust

Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2015 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission. Market capitalization and name of largest company in each decile are as of Sept. 30, 2014.

Long-Term Returns in Excess of Systematic Risk

The capital asset pricing model, or CAPM, does not fully account for the higher returns of small-cap stocks. Table 7-6 shows the returns in excess of the riskless rate over the past 89 years for each decile of the NYSE/AMEX/NASDAQ.

The CAPM can be expressed as follows:

$$k_s = r_f + (\beta_s \times ERP)$$

where,

k_s = the expected return for company **s**;
r_f = the expected return of the riskless asset;
β_s = the beta of the stock of company **s**; and,
ERP = the expected equity risk premium, or the amount by which investors expect the future return on equities to exceed that on the riskless asset.

Table 7-6 uses the CAPM to estimate the return in excess of the riskless rate and compares this estimate to historical performance. According to the CAPM, the expected return on a security should consist of the riskless rate plus an additional return to compensate for the systematic risk of the security. The return in excess of the riskless rate is estimated in the context of the CAPM by multiplying the equity risk premium by β (beta). The equity risk premium is the return that compensates investors for taking on risk equal to the risk of the market as a whole (systematic risk). Beta measures the extent to which a security or portfolio is exposed to systematic risk. The beta of each decile indicates the degree to which the decile's return moves with that of the overall market.

A beta greater than one indicates that the security or portfolio has greater systematic risk than the market; according to the CAPM equation, investors are compensated for taking on this additional risk. Yet, Table 7-6 illustrates that the smaller deciles have had returns that are not fully explained by their higher betas. This return in excess of that predicted by CAPM increases as one moves from the largest companies in decile 1 to the smallest in decile 10. The excess return is especially pronounced for micro-cap stocks (deciles 9-10). This size-related phenomenon has prompted a revision to the CAPM, which includes a size premium.

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The model is analogous to the standard CAPM, but with the return on a minimum risk portfolio that is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who find a flatter than predicted SML, consistent with the model and other researchers' findings. An updated version of the Black-Jensen-Scholes study is available in Brealey, Myers, and Allen (2006) and reaches similar conclusions.

The zero-beta CAPM cannot be literally employed to estimate the cost of capital, since the zero-beta portfolio is a statistical construct difficult to replicate. Attempts to estimate the model are formally equivalent to estimating the constants, a and b, in Equation 6-2. A practical alternative is to employ the Empirical CAPM, to which we now turn.

6.3 Empirical CAPM

As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha}) \qquad (6\text{-}5)$$

where $\acute{\alpha}$ is the "alpha" of the risk-return line, a constant, and the other symbols are defined as before. All the potential vagaries of the CAPM are telescoped into the constant $\acute{\alpha}$, which must be estimated econometrically from market data. Table 6-2 summarizes[10] the empirical evidence on the magnitude of alpha.[11]

[10] The technique is formally applied by Litzenberger, Ramaswamy, and Sosin (1980) to public utilities in order to rectify the CAPM's basic shortcomings. Not only do they summarize the criticisms of the CAPM insofar as they affect public utilities, but they also describe the econometric intricacies involved and the methods of circumventing the statistical problems. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities grouped into portfolios are related to their corresponding betas by statistical regression techniques; that is, Equation 6-5 is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their own results demonstrate how the standard CAPM underestimates the cost of equity capital of public utilities because of utilities' high dividend yield and return skewness.

[11] Adapted from Vilbert (2004).

TABLE 6-2
EMPIRICAL EVIDENCE ON THE ALPHA FACTOR

Author	Range of alpha
Fischer (1993)	−3.6% to 3.6%
Fischer, Jensen and Scholes (1972)	−9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

For an alpha in the range of 1%–2% and for reasonable values of the market risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F) \qquad (6\text{-}6)$$

Over reasonable values of the risk-free rate and the market risk premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.[12]

An alpha range of 1%–2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the

[12] Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926–1984 was given by:

$$\text{Return} = 0.0829 + 0.0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6% and that the market risk premium was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and that the slope of the relationship is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1 - x)\beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return $= 0.0829 + 0.0520\,\beta$ is between 0.25 and 0.30. If $x = 0.25$, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[13]

To illustrate the application of the ECAPM, assume a risk-free rate of 5%, a market risk premium of 7%, and a beta of 0.80. The Empirical CAPM equation (6-6) above yields a cost of equity estimate of 11.0% as follows:

$$\begin{aligned} K &= 5\% + 0.25\,(12\% - 5\%) + 0.75 \times 0.80\,(12\% - 5\%) \\ &= 5.0\% + 1.8\% + 4.2\% \\ &= 11.0\% \end{aligned}$$

As an alternative to specifying alpha, see Example 6-1.

Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

[13] The lowering of the tax burden on capital gains and dividend income has no impact as far as non-taxable institutional investors (pension funds, 401K, and mutual funds) are concerned, and such investors engage in very large amounts of trading on security markets. It is quite plausible that taxable retail investors are relatively inactive traders and that large non-taxable investors have a substantial influence on capital markets.

The Risk Premium Approach to Measuring a Utility's Cost of Equity

Eugene F. Brigham; Dilip K. Shome; Steve R. Vinson

Financial Management, Vol. 14, No. 1. (Spring, 1985), pp. 33-45.

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Cost of Capital Estimation

The Risk Premium Approach to Measuring a Utility's Cost of Equity

Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson

Eugene F. Brigham and Dilip K. Shome are faculty members of the University of Florida and the Virginia Polytechnic Institute and State University, respectively; Steve R. Vinson is affiliated with AT&T Communications.

■ In the mid-1960s, Myron Gordon and others began applying the theory of finance to help estimate utilities' costs of capital. Previously, the standard approach in cost of equity studies was the "comparable earnings method," which involved selecting a sample of unregulated companies whose investment risk was judged to be comparable to that of the utility in question, calculating the average return on book equity (ROE) of these sample companies, and setting the utility's service rates at a level that would permit the utility to achieve the same ROE as comparable companies. This procedure has now been thoroughly discredited (see Robichek [15]), and it has been replaced by three market-oriented (as opposed to accounting-oriented) approaches: (i) the DCF method, (ii) the bond-yield-plus-risk-premium method, and (iii) the CAPM, which is a specific version of the generalized bond-yield-plus-risk-premium approach.

Our purpose in this paper is to discuss the risk-premium approach, including the market risk premium that is used in the CAPM. First, we critique the various procedures that have been used in the past to estimate risk premiums. Second, we present some data on estimated risk premiums since 1965. Third, we examine the relationship between equity risk premiums and the level of interest rates, because it is important, for purposes of estimating the cost of capital, to know just how stable the relationship between risk premiums and interest rates is over time. If stability exists, then one can estimate the cost of equity at any point in time as a function of interest rates as reported in *The Wall Street Journal*, the *Federal Reserve Bulletin*, or some similar source.[1] Fourth, while we do not discuss the CAPM directly, our analysis does have some important implications for selecting a market risk premium for use in that model. Our focus is on utilities, but the methodology is applicable to the estimation of the cost of

[1]For example, the Federal Energy Regulatory Commission's Staff recently proposed that a risk premium be estimated every two years and that, between estimation dates, the last-determined risk premium be added to the current yield on ten-year Treasury bonds to obtain an estimate of the cost of equity to an average utility (Docket RM 80–36). Subsequently, the FCC made a similar proposal ("Notice of Proposed Rulemaking," August 13, 1984, Docket No. 84–800). Obviously, the validity of such procedures depends on (i) the accuracy of the risk premium estimate and (ii) the stability of the relationship between risk premiums and interest rates. Both proposals are still under review.

equity for any publicly traded firm, and also for non-traded firms for which an appropriate risk class can be assessed, including divisions of publicly traded corporations.[2]

Alternative Procedures for Estimating Risk Premiums

In a review of both rate cases and the academic literature, we have identified three basic methods for estimating equity risk premiums: (i) the *ex post*, or historic, yield spread method; (ii) the survey method; and (iii) an *ex ante* yield spread method based on DCF analysis.[3] In this section, we briefly review these three methods.

Historic Risk Premiums

A number of researchers, most notably Ibbotson and Sinquefield [12], have calculated historic holding period returns on different securities and then estimated risk premiums as follows:

$$\text{Historic Risk Premium} = \left\{\begin{array}{c}\text{Average of the annual returns on a stock index for a particular past period}\end{array}\right\} - \left\{\begin{array}{c}\text{Average of the annual returns on a bond index for the same past period}\end{array}\right\} . \quad (1)$$

Ibbotson and Sinquefield (I&S) calculated both arithmetic and geometric average returns, but most of their risk-premium discussion was in terms of the geometric averages. Also, they used both corporate and Treasury bond indices, as well as a T-bill index, and they analyzed all possible holding periods since 1926. The I&S study has been employed in numerous rate cases in two ways: (i) directly, where the I&S historic risk premium is added to a company's bond yield to obtain an estimate of its cost of equity, and (ii) indirectly, where I&S data are used to estimate the market risk premium in CAPM studies.

There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome. These measurement problems are common to most forecasts based on time series data.

The Survey Approach

One obvious way to estimate equity risk premiums is to poll investors. Charles Benore [1], the senior utility analyst for Paine Webber Mitchell Hutchins, a leading institutional brokerage house, conducts such a survey of major institutional investors annually. His 1983 results are reported in Exhibit 1.

Exhibit 1. Results of Risk Premium Survey, 1983*

Assuming a double A, long-term utility bond currently yields 12½%, the common stock for the same company would be fairly priced relative to the bond if its expected return was as follows:

Total Return	Indicated Risk Premium (basis points)	Percent of Respondents
over 20½%	over 800	
20½%	800	
19½%	700	
18½%	600	10%
17½%	500	8%
16½%	400	29%
15½%	300	35%
14½%	200	16%
13½%	100	0%
under 13½%	under 100	1%
Weighted average	358	100%

*Benore's questionnaire included the first two columns, while his third column provided a space for the respondents to indicate which risk premium they thought applied. We summarized Benore's responses in the frequency distribution given in Column 3. Also, in his questionnaire each year, Benore adjusts the double A bond yield and the total returns (Column 1) to reflect current market conditions. Both the question above and the responses to it were taken from the survey conducted in April 1983.

[2]The FCC is particularly interested in risk-premium methodologies, because (i) only eighteen of the 1,400 telephone companies it regulates have publicly-traded stock, and hence offer the possibility of DCF analysis, and (ii) most of the publicly-traded telephone companies have both regulated and unregulated assets, so a corporate DCF cost might not be applicable to the regulated units of the companies.

[3]In rate cases, some witnesses also have calculated the differential between the yield to maturity (YTM) of a company's bonds and its concurrent ROE, and then called this differential a risk premium. In general, this procedure is unsound, because the YTM on a bond is a *future expected* return on the bond's *market value*, while the ROE is the *past realized* return on the stock's *book value*. Thus, comparing YTMs and ROEs is like comparing apples and oranges.

Benore's results, as measured by the average risk premiums, have varied over the years as follows:

Year	Average RP (basis points)
1978	491
1979	475
1980	423
1981	349
1982	275
1983	358

The survey approach is conceptually sound in that it attempts to measure investors' expectations regarding risk premiums, and the Benore data also seem to be carefully collected and processed. Therefore, the Benore studies do provide one useful basis for estimating risk premiums. However, as with most survey results, the possibility of biased responses and/or biased sampling always exists. For example, if the responding institutions are owners of utility stocks (and many of them are), and if the respondents think that the survey results might be used in a rate case, then they might bias upward their responses to help utilities obtain higher authorized returns. Also, Benore surveys large institutional investors, whereas a high percentage of utility stocks are owned by individuals rather than institutions, so there is a question as to whether his reported risk premiums are really based on the expectations of the "representative" investor. Finally, from a pragmatic standpoint, there is a question as to how to use the Benore data for utilities that are not rated AA. The Benore premiums can be applied as an add-on to the own-company bond yields of any given utility only if it can be assumed that the premiums are constant across bond rating classes. *A priori*, there is no reason to believe that the premiums will be constant.

DCF-Based *Ex Ante* Risk Premiums

In a number of studies, the DCF model has been used to estimate the *ex ante* market risk premium, RP_M. Here, one estimates the average expected future return on equity for a group of stocks, k_M, and then subtracts the concurrent risk-free rate, R_F, as proxied by the yield to maturity on either corporate or Treasury securities:[4]

$$RP_M = k_M - R_F. \tag{2}$$

Conceptually, this procedure is exactly like the I&S approach except that one makes direct estimates of future expected returns on stocks and bonds rather than assuming that investors expect future returns to mirror past returns.

The most difficult task, of course, is to obtain a valid estimate of k_M, the expected rate of return on the market. Several studies have attempted to estimate DCF risk premiums for the utility industry and for other stock market indices. Two of these are summarized next.

Vandell and Kester. In a recently published monograph, Vandell and Kester [18] estimated *ex ante* risk premiums for the period from 1944 to 1978. R_F was measured both by the yield on 90-day T-bills and by the yield on the Standard and Poor's AA Utility Bond Index. They measured k_M as the average expected return on the S&P's 500 Index, with the expected return on individual securities estimated as follows:

$$k_i = \left(\frac{D_1}{P_0}\right)_i + g_i, \tag{3}$$

where,

D_1 = dividend per share expected over the next twelve months,
P_0 = current stock price,
g = estimated long-term constant growth rate, and
i = the i^{th} stock.

To estimate g_i, Vandell and Kester developed fifteen forecasting models based on both exponential smoothing and trend-line forecasts of earnings and dividends, and they used historic data over several estimating horizons. Vandell and Kester themselves acknowledge that, like the Ibbotson-Sinquefield premiums, their analysis is subject to potential errors associated with trying to estimate expected future growth purely from past data. We shall have more to say about this point later.

[4]In this analysis, most people have used yields on long-term bonds rather than short-term money market instruments. It is recognized that long-term bonds, even Treasury bonds, are not risk free, so an RP_M based on these debt instruments is smaller than it would be if there were some better proxy to the long-term riskless rate. People have attempted to use the T-bill rate for R_F, but the T-bill rate embodies a different average inflation premium than stocks, and it is subject to random fluctuations caused by monetary policy, international currency flows, and other factors. Thus, many people believe that for cost of capital purposes, R_F should be based on long-term securities.

We did test to see how debt maturities would affect our calculated risk premiums. If a short-term rate such as the 30-day T-bill rate is used, measured risk premiums jump around widely and, so far as we could tell, randomly. The choice of a maturity in the 10- to 30-year range has little effect, as the yield curve is generally fairly flat in that range.

Malkiel. Malkiel [14] estimated equity risk premiums for the Dow Jones Industrials using the DCF model. Recognizing that the constant dividend growth assumption may not be valid, Malkiel used a nonconstant version of the DCF model. Also, rather than rely exclusively on historic data, he based his growth rates on Value Line's five-year earnings growth forecasts plus the assumption that each company's growth rate would, after an initial five-year period, move toward a long-run real national growth rate of four percent. He also used ten-year maturity government bonds as a proxy for the riskless rate. Malkiel reported that he tested the sensitivity of his results against a number of different types of growth rates, but, in his words, "The results are remarkably robust, and the estimated risk premiums are all very similar." Malkiel's is, to the best of our knowledge, the first risk-premium study that uses analysts' forecasts. A discussion of analysts' forecasts follows.

Security Analysts' Growth Forecasts

Ex ante DCF risk premium estimates can be based either on expected growth rates developed from time series data, such as Vandell and Kester used, or on analysts' forecasts, such as Malkiel used. Although there is nothing inherently wrong with time series-based growth rates, an increasing body of evidence suggests that primary reliance should be placed on analysts' growth rates. First, we note that the observed market price of a stock reflects the consensus view of investors regarding its future growth. Second, we know that most large brokerage houses, the larger institutional investors, and many investment advisory organizations employ security analysts who forecast future EPS and DPS, and, to the extent that investors rely on analysts' forecasts, the consensus of analysts' forecasts is embodied in market prices. Third, there have been literally dozens of academic research papers dealing with the accuracy of analysts' forecasts, as well as with the extent to which investors actually use them. For example, Cragg and Malkiel [7] and Brown and Rozeff [5] determined that security analysts' forecasts are more relevant in valuing common stocks and estimating the cost of capital than are forecasts based solely on historic time series. Stanley, Lewellen, and Schlarbaum [16] and Linke [13] investigated the importance of analysts' forecasts and recommendations to the investment decisions of individual and institutional investors. Both studies indicate that investors rely heavily on analysts' reports and incorporate analysts' forecast information in the formation of their expectations about stock returns. A representative listing of other work supporting the use of analysts' forecasts is included in the References section. Thus, evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts. Accordingly, we based our cost of equity, and hence risk premium estimates, on analysts' forecast data.[5]

Risk Premium Estimates

For purposes of estimating the cost of capital using the risk premium approach, it is necessary either that the risk premiums be time-invariant or that there exists a predictable relationship between risk premiums and interest rates. If the premiums are constant over time, then the constant premium could be added to the prevailing interest rate. Alternatively, if there exists a stable relationship between risk premiums and interest rates, it could be used to predict the risk premium from the prevailing interest rate.

To test for stability, we obviously need to calculate risk premiums over a fairly long period of time. Prior to 1980, the only consistent set of data we could find came from Value Line, and, because of the work involved, we could develop risk premiums only once a year (on January 1). Beginning in 1980, however, we began collecting and analyzing Value Line data on a monthly basis, and in 1981 we added monthly estimates from Merrill Lynch and Salomon Brothers to our data base. Finally, in mid-1983, we expanded our analysis to include the IBES data.

Annual Data and Results, 1966–1984

Over the period 1966–1984, we used Value Line data to estimate risk premiums both for the electric utility industry and for industrial companies, using the companies included in the Dow Jones Industrial and Utility averages as representative of the two groups. Value Line makes a five-year growth rate forecast, but it also gives data from which one can develop a longer-term forecast. Since DCF theory calls for a truly long-term (infinite horizon) growth rate, we concluded that it was better to develop and use such a forecast than to

[5]Recently, a new type of service that summarizes the key data from most analysts' reports has become available. We are aware of two sources of such services, the Lynch, Jones, and Ryan's Institutional Brokers Estimate System (IBES) and Zack's Icarus Investment Service. IBES and the Icarus Service gather data from both buy-side and sell-side analysts and provide it to subscribers on a monthly basis in both a printed and a computer-readable format.

Exhibit 2. Estimated Annual Risk Premiums, Nonconstant (Value Line) Model, 1966–1984

January 1 of the Year Reported	Dow Jones Electrics			Dow Jones Industrials			
	k_{Avg}	R_F	RP	k_{Avg}	R_F	RP	(3) ÷ (6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1966	8.11%	4.50%	3.61%	9.56%	4.50%	5.06%	0.71
1967	9.00%	4.76%	4.24%	11.57%	4.76%	6.81%	0.62
1968	9.68%	5.59%	4.09%	10.56%	5.59%	4.97%	0.82
1969	9.34%	5.88%	3.46%	10.96%	5.88%	5.08%	0.68
1970	11.04%	6.91%	4.13%	12.22%	6.91%	5.31%	0.78
1971	10.80%	6.28%	4.52%	11.23%	6.28%	4.95%	0.91
1972	10.53%	6.00%	4.53%	11.09%	6.00%	5.09%	0.89
1973	11.37%	5.96%	5.41%	11.47%	5.96%	5.51%	0.98
1974	13.85%	7.29%	6.56%	12.38%	7.29%	5.09%	1.29
1975	16.63%	7.91%	8.72%	14.83%	7.91%	6.92%	1.26
1976	13.97%	8.23%	5.74%	13.32%	8.23%	5.09%	1.13
1977	12.96%	7.30%	5.66%	13.63%	7.30%	6.33%	0.89
1978	13.42%	7.87%	5.55%	14.75%	7.87%	6.88%	0.81
1979	14.92%	8.99%	5.93%	15.50%	8.99%	6.51%	0.91
1980	16.39%	10.18%	6.21%	16.53%	10.18%	6.35%	0.98
1981	17.61%	11.99%	5.62%	17.37%	11.99%	5.38%	1.04
1982	17.70%	14.00%	3.70%	19.30%	14.00%	5.30%	0.70
1983	16.30%	10.66%	5.64%	16.53%	10.66%	5.87%	0.96
1984	16.03%	11.97%	4.06%	15.72%	11.97%	3.75%	1.08

use the five-year prediction.[6] Therefore, we obtained data as of January 1 from Value Line for each of the Dow Jones companies and then solved for k, the expected rate of return, in the following equation:

$$P_0 = \sum_{t=1}^{n} \frac{D_t}{(1+k)^t} + \left(\frac{D_n(1+g_n)}{k-g_n}\right)\left(\frac{1}{1+k}\right)^n. \qquad (4)$$

Equation (4) is the standard nonconstant growth DCF model; P_0 is the current stock price; D_t represents the forecasted dividends during the nonconstant growth period; n is the years of nonconstant growth; D_n is the first constant growth dividend; and g_n is the constant, long-run growth rate after year n. Value Line provides D_t values for t = 1 and t = 4, and we interpolated to obtain D_2 and D_3. Value Line also gives estimates for ROE and for the retention rate (b) in the terminal year, n, so we can forecast the long-term growth rate as $g_n = b(ROE)$. With all the values in Equation (4) specified except k, we can solve for k, which is the DCF rate of return that would result if the Value Line forecasts were met, and, hence, the DCF rate of return implied in the Value Line forecast.[7]

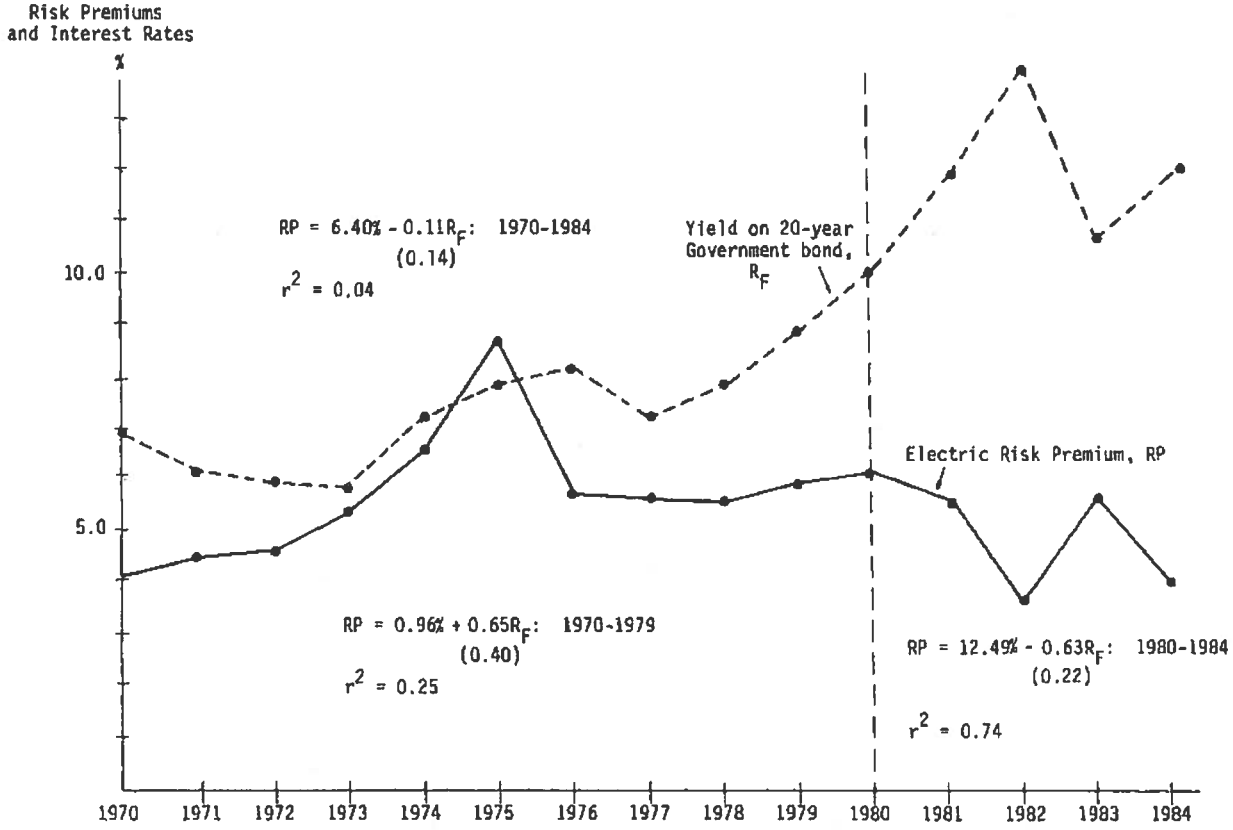
Having estimated a k value for each of the electric and industrial companies, we averaged them (using market-value weights) to obtain a k value for each group, after which we subtracted R_F (taken as the December 31 yield on twenty-year constant maturity Treasury bonds) to obtain the estimated risk premiums shown in Exhibit 2. The premiums for the electrics are plotted in Exhibit 3, along with interest rates. The following points are worthy of note:

1. Risk premiums fluctuate over time. As we shall see in the next section, fluctuations are even wider when measured on a monthly basis.
2. The last column of Exhibit 2 shows that risk premi-

[6]This is a debatable point. Cragg and Malkiel, as well as many practicing analysts, feel that most investors actually focus on five-year forecasts. Others, however, argue that five-year forecasts are too heavily influenced by base-year conditions and/or other nonpermanent conditions for use in the DCF model. We note (i) that most published forecasts do indeed cover five years, (ii) that such forecasts are typically "normalized" in some fashion to alleviate the base-year problem, and (iii) that for relatively stable companies like those in the Dow Jones averages, it generally does not matter greatly if one uses a normalized five-year or a longer-term forecast, because these companies meet the conditions of the constant-growth DCF model rather well.

[7]Value Line actually makes an explicit price forecast for each stock, and one could use this price, along with the forecasted dividends, to develop an expected rate of return. However, Value Line's forecasted stock price builds in a forecasted *change* in k. Therefore, the forecasted price is inappropriate for use in estimating current values of k.

Exhibit 3. Equity Risk Premiums for Electric Utilities and Yields on 20-Year Government Bonds, 1970–1984*



*Standard errors of the coefficients are shown in parentheses below the coefficients.

ums for the utilities increased relative to those for the industrials from the mid-1960s to the mid-1970s. Subsequently, the perceived riskiness of the two groups has, on average, been about the same.

3. Exhibit 3 shows that, from 1970 through 1979, utility risk premiums tended to have a positive association with interest rates: when interest rates rose, so did risk premiums, and vice versa. However, beginning in 1980, an inverse relationship appeared: rising interest rates led to declining risk premiums. We shall discuss this situation further in the next section.

Monthly Data and Results, 1980–1984

In early 1980, we began calculating risk premiums on a monthly basis. At that time, our only source of analysts' forecasts was Value Line, but beginning in 1981 we also obtained Merrill Lynch and Salomon Brothers' data, and then, in mid-1983, we obtained IBES data. Because our focus was on utilities, we restricted our monthly analysis to that group.

Our 1980–1984 monthly risk premium data, along with Treasury bond yields, are shown in Exhibits 4 and 5 and plotted in Exhibits 6, 7, and 8. Here are some comments on these Exhibits:

1. Risk premiums, like interest rates and stock prices, are volatile. Our data indicate that it would not be appropriate to estimate the cost of equity by adding the current cost of debt to a risk premium that had been estimated in the past. Current risk premiums should be matched with current interest rates.
2. Exhibit 6 confirms the 1980–1984 section of Exhibit 3 in that it shows a strong inverse relationship between interest rates and risk premiums; we shall discuss shortly why this relationship holds.
3. Exhibit 7 shows that while risk premiums based on Value Line, Merrill Lynch, and Salomon Brothers

Exhibit 4. Estimated Monthly Risk Premiums for Electric Utilities Using Analysts' Growth Forecasts, January 1980–June 1984

Beginning of Month	Value Line	Merrill Lynch	Salomon Brothers	Average Premiums	20-Year Treasury Bond Yield, Constant Maturity Series
Jan 1980	6.21%	NA	NA	6.21%	10.18%
Feb 1980	5.77%	NA	NA	5.77%	10.86%
Mar 1980	4.73%	NA	NA	4.73%	12.59%
Apr 1980	5.02%	NA	NA	5.02%	12.71%
May 1980	4.73%	NA	NA	4.73%	11.04%
Jun 1980	5.09%	NA	NA	5.09%	10.37%
Jul 1980	5.41%	NA	NA	5.41%	9.86%
Aug 1980	5.72%	NA	NA	5.72%	10.29%
Sep 1980	5.16%	NA	NA	5.16%	11.41%
Oct 1980	5.62%	NA	NA	5.62%	11.75%
Nov 1980	5.09%	NA	NA	5.09%	12.33%
Dec 1980	5.65%	NA	NA	5.65%	12.37%
Annual Avg.	5.35%			5.35%	11.31%
Jan 1981	5.62%	4.76%	5.63%	5.34%	11.99%
Feb 1981	4.82%	4.87%	5.16%	4.95%	12.48%
Mar 1981	4.70%	3.73%	4.97%	4.47%	13.10%
Apr 1981	4.24%	3.23%	4.52%	4.00%	13.11%
May 1981	3.54%	3.24%	4.24%	3.67%	13.51%
Jun 1981	3.57%	4.04%	4.27%	3.96%	13.39%
Jul 1981	3.61%	3.63%	4.16%	3.80%	13.32%
Aug 1981	3.17%	3.05%	3.04%	3.09%	14.23%
Sep 1981	2.11%	2.24%	2.35%	2.23%	14.99%
Oct 1981	2.83%	2.64%	3.24%	2.90%	14.93%
Nov 1981	2.08%	2.49%	3.03%	2.53%	15.27%
Dec 1981	3.72%	3.45%	4.24%	3.80%	13.12%
Annual Avg.	3.67%	3.45%	4.07%	3.73%	13.62%
Jan 1982	3.70%	3.37%	4.04%	3.70%	14.00%
Feb 1982	3.05%	3.37%	3.70%	3.37%	14.37%
Mar 1982	3.15%	3.28%	3.75%	3.39%	13.96%
Apr 1982	3.49%	3.61%	4.29%	3.80%	13.69%
May 1982	3.08%	4.25%	3.91%	3.75%	13.47%
Jun 1982	3.16%	4.51%	4.72%	4.13%	13.53%
Jul 1982	2.57%	4.21%	4.21%	3.66%	14.48%
Aug 1982	4.33%	4.83%	5.27%	4.81%	13.69%
Sep 1982	4.08%	5.14%	5.58%	4.93%	12.40%
Oct 1982	5.35%	5.24%	6.34%	5.64%	11.95%
Nov 1982	5.67%	5.95%	6.91%	6.18%	10.97%
Dec 1982	6.31%	6.71%	7.45%	6.82%	10.52%
Annual Avg.	4.00%	4.54%	5.01%	4.52%	13.09%
Jan 1983	5.64%	6.04%	6.81%	6.16%	10.66%
Feb 1983	4.68%	5.99%	6.10%	5.59%	11.01%
Mar 1983	4.99%	6.89%	6.43%	6.10%	10.71%
Apr 1983	4.75%	5.82%	6.31%	5.63%	10.84%
May 1983	4.50%	6.41%	6.24%	5.72%	10.57%
Jun 1983	4.29%	5.21%	6.16%	5.22%	10.90%
Jul 1983	4.78%	5.72%	6.42%	5.64%	11.12%
Aug 1983	3.89%	4.74%	5.41%	4.68%	11.78%
Sep 1983	4.07%	4.90%	5.57%	4.85%	11.71%
Oct 1983	3.79%	4.64%	5.38%	4.60%	11.64%
Nov 1983	2.84%	3.77%	4.46%	3.69%	11.90%
Dec 1983	3.36%	4.27%	5.00%	4.21%	11.83%
Annual Avg.	4.30%	5.37%	5.86%	5.17%	11.22%
Jan 1984	4.06%	5.04%	5.65%	4.92%	11.97%
Feb 1984	4.25%	5.37%	5.96%	5.19%	11.76%
Mar 1984	4.73%	6.05%	6.38%	5.72%	12.12%
Apr 1984	4.78%	5.33%	6.32%	5.48%	12.51%
May 1984	4.36%	5.30%	6.42%	5.36%	12.78%
Jun 1984	3.54%	4.00%	5.63%	4.39%	13.60%

Exhibit 5. Monthly Risk Premiums Based on IBES Data

Beginning of Month	Average of Merrill Lynch, Salomon Brothers, and Value Line Premiums for Dow Jones Electrics	IBES Premiums for Dow Jones Electrics	IBES Premiums for Entire Electric Industry
Aug 1983	4.68%	4.10%	4.16%
Sep 1983	4.85%	4.43%	4.27%
Oct 1983	4.60%	4.31%	3.90%
Nov 1983	3.69%	3.36%	3.36%
Dec 1983	4.21%	3.86%	3.54%
Jan 1984	4.92%	4.68%	4.18%
Feb 1984	5.19%	5.00%	4.36%
Mar 1984	5.72%	5.35%	4.45%
Apr 1984	5.48%	5.33%	4.23%
May 1984	5.36%	5.26%	4.30%
Jun 1984	4.39%	4.47%	3.40%
Average Premiums	4.83%	4.56%	4.01%

Exhibit 6. Utility Risk Premiums and Interest Rates, 1980–1984

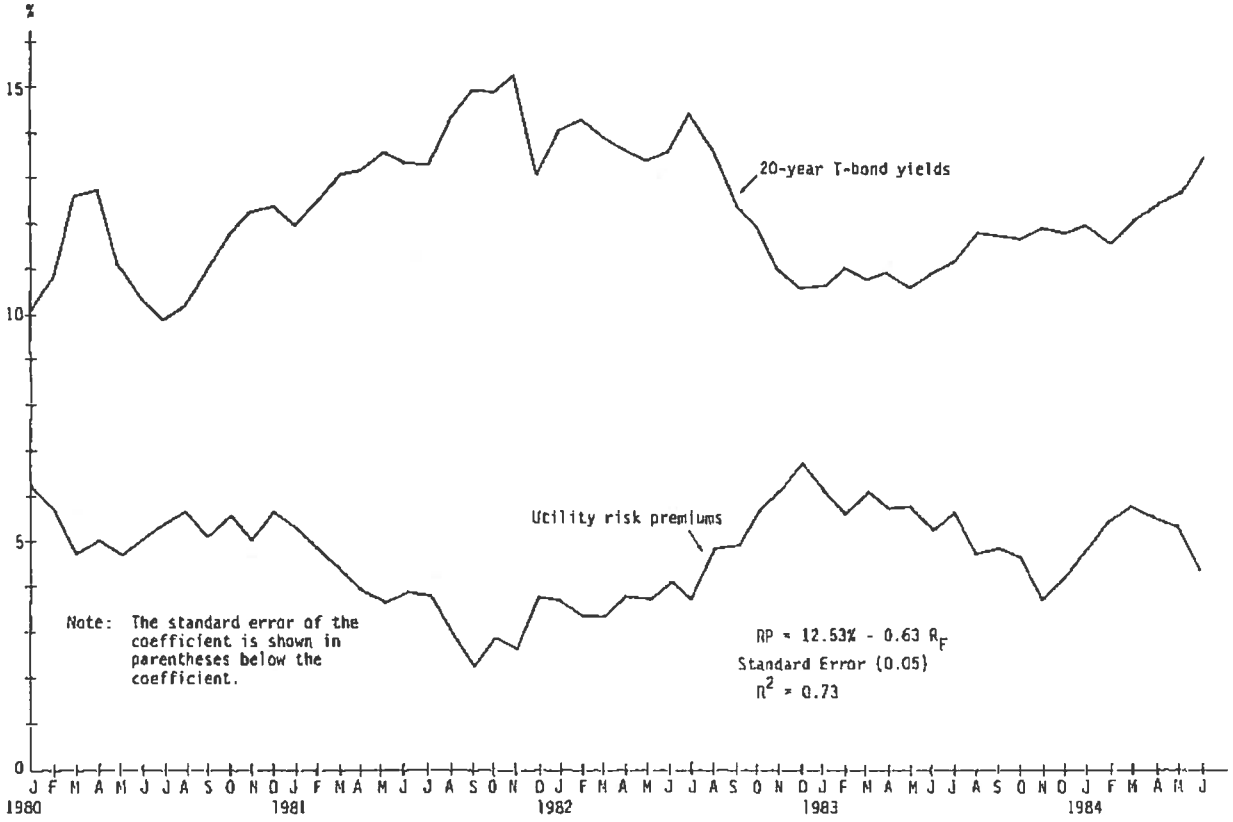


Exhibit 7. Monthly Risk Premiums, Electric Utilities, 1981–1984 (to Date)

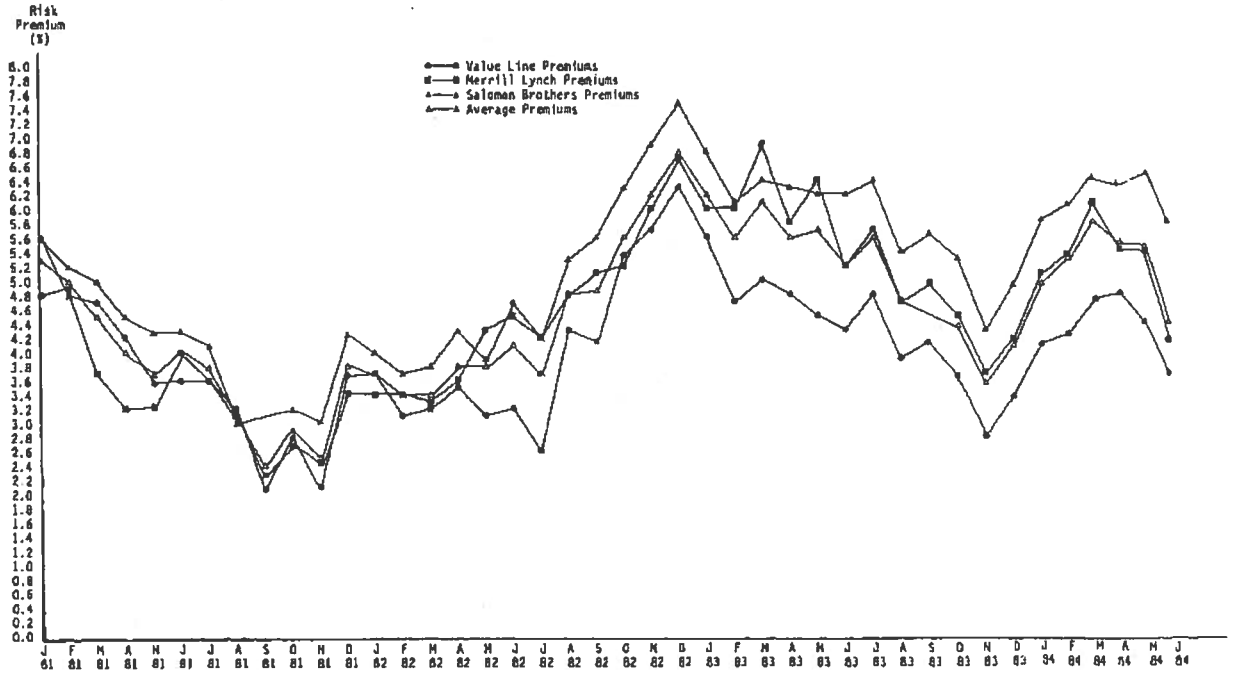
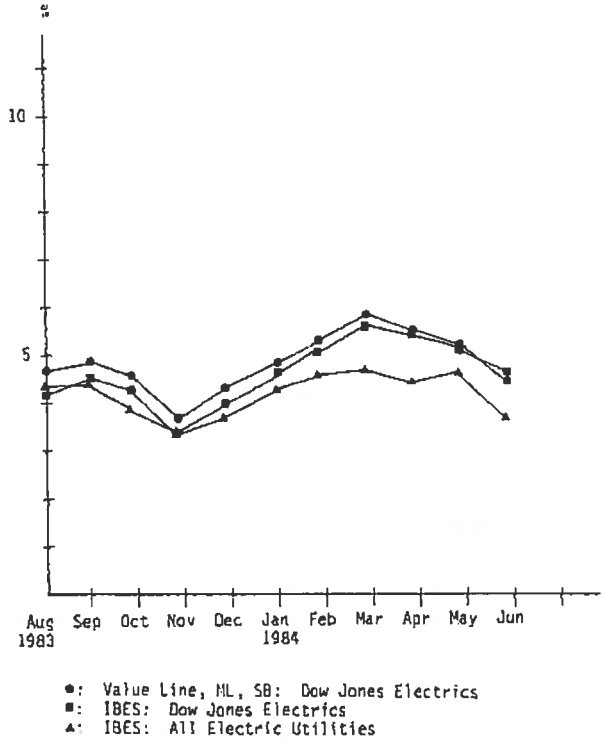


Exhibit 8. Comparative Risk Premium Data



do differ, the differences are not large given the nature of the estimates, and the premiums follow one another closely over time. Since all of the analysts are examining essentially the same data and since utility companies are not competitive with one another, and hence have relatively few secrets, the similarity among the analysts' forecasts is not surprising.

4. The IBES data, presented in Exhibit 5 and plotted in Exhibit 8, contain too few observations to enable us to draw strong conclusions, but (i) the Dow Jones Electrics risk premiums based on our three-analyst data have averaged 27 basis points above premiums based on the larger group of analysts surveyed by IBES and (ii) the premiums on the 11 Dow Jones Electrics have averaged 54 basis points higher than premiums for the entire utility industry followed by IBES. Given the variability in the data, we are, at this point, inclined to attribute these differences to random fluctuations, but as more data become available, it may turn out that the differences are statistically significant. In particular, the 11 electric utilities included in the Dow Jones Utility Index all have large nuclear investments, and this may cause them to be regarded as riskier than the industry average, which includes both nuclear and non-nuclear companies.

Tests of the Reasonableness of the Risk Premium Estimates

So far our claims to the reasonableness of our risk-premium estimates have been based on the reasonableness of our variable measures, particularly the measures of expected dividend growth rates. Essentially, we have argued that since there is strong evidence in the literature in support of analysts' forecasts, risk premiums based on these forecasts are reasonable. In the spirit of positive economics, however, it is also important to demonstrate the reasonableness of our results more directly.

It is theoretically possible to test for the validity of the risk-premium estimates in a CAPM framework. In a cross-sectional estimate of the CAPM equation,

$$(k - R_F)_i = \alpha_0 + \alpha_1\beta_i + u_i, \qquad (5)$$

we would expect

$$\hat{\alpha}_0 = 0 \text{ and } \hat{\alpha}_1 = k_M - R_F = \text{Market risk premium.}$$

This test, of course, would be a joint test of both the CAPM and the reasonableness of our risk-premium estimates. There is a great deal of evidence that questions the empirical validity of the CAPM, especially when applied to regulated utilities. Under these conditions, it is obvious that no unambiguous conclusion can be drawn regarding the efficacy of the premium estimates from such a test.[8]

A simpler and less ambiguous test is to show that the risk premiums are higher for lower rated firms than for higher rated firms. Using 1984 data, we classified the

[8]We carried out the test on a monthly basis for 1984 and found positive but statistically insignificant coefficients. A typical result (for April 1984) follows:

$$(k - R_F)_i = \underset{(0.91)}{3.1675} + \underset{(1.44)}{1.8031}\,\beta_i.$$

The figures in parentheses are standard errors. Utility risk premiums do increase with betas, but the intercept term is not zero as the CAPM would predict, and α_1 is both less than the predicted value and not statistically significant. Again, the observation that the coefficients do not conform to CAPM predictions could be as much a problem with CAPM specification for utilities as with the risk premium estimates.

A similar test was carried out by Friend, Westerfield, and Granito [9]. They tested the CAPM using expectational (survey) data rather than *ex post* holding period returns. They actually found their coefficient of β_i to be negative in all their cross-sectional tests.

Exhibit 9. Relationship between Risk Premiums and Bond Ratings, 1984*

Month	Aaa/AA	AA	Aa/A	A	A/BBB	BBB	Below BBB
January†	—	2.61%	3.06%	3.70%	5.07%	4.90%	9.45%
February	2.98%	3.17%	3.36%	4.03%	5.26%	5.14%	7.97%
March	2.34%	3.46%	3.29%	4.06%	5.43%	5.02%	8.28%
April	2.37%	3.03%	3.29%	3.88%	5.29%	4.97%	6.96%
May	2.00%	2.48%	3.42%	3.72%	4.72%	6.64%	8.81%
June	0.72%	2.17%	2.46%	3.16%	3.76%	5.00%	5.58%
Average	2.08%	2.82%	3.15%	3.76%	4.92%	5.28%	7.84%

*The risk premiums are based on IBES data for the electric utilities followed by both IBES and Salomon Brothers. The number of electric utilities followed by both firms varies from month to month. For the period between January and June 1984, the number of electrics followed by both firms ranged from 96 to 99 utilities.
†In January, there were no Aaa/AA companies. Subsequently, four utilities were upgraded to Aaa/AA.

utility industry into risk groups based on bond ratings. For each rating group, we estimated the average risk premium. The results, presented in Exhibit 9, clearly show that the lower the bond rating, the higher the risk premiums. Our premium estimates therefore would appear to pass this simple test of reasonableness.

Risk Premiums and Interest Rates

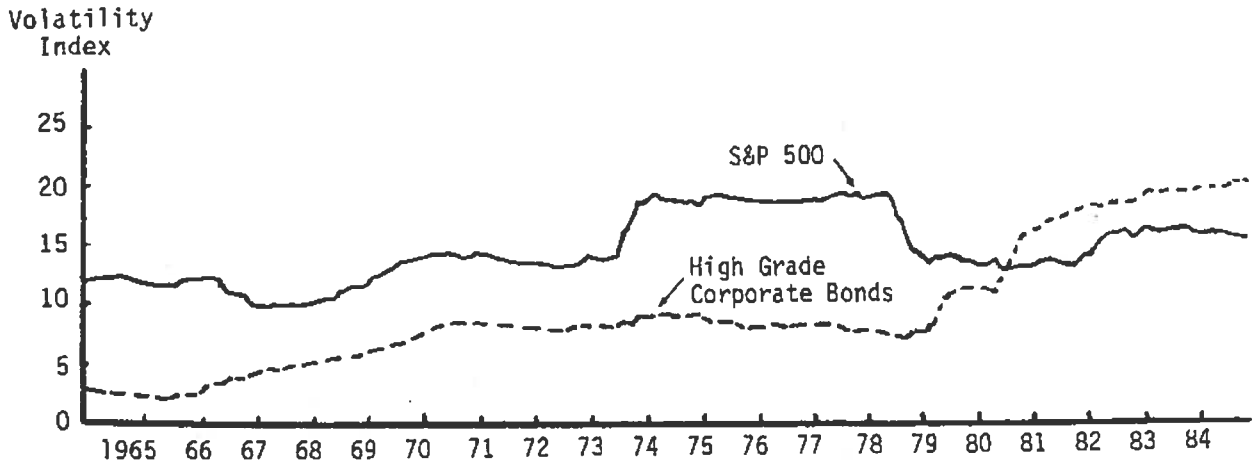
Traditionally, stocks have been regarded as being riskier than bonds because bondholders have a prior claim on earnings and assets. That is, stockholders stand at the end of the line and receive income and/or assets only after the claims of bondholders have been satisfied. However, if interest rates fluctuate, then the holders of long-term bonds can suffer losses (either realized or in an opportunity cost sense) even though they receive all contractually due payments. Therefore, if investors' worries about "interest rate risk" versus "earning power risk" vary over time, then perceived risk differentials between stocks and bonds, and hence risk premiums, will also vary.

Any number of events could occur to cause the perceived riskiness of stocks versus bonds to change, but probably the most pervasive factor, over the 1966–1984 period, is related to inflation. Inflationary expectations are, of course, reflected in interest rates. Therefore, one might expect to find a relationship between risk premiums and interest rates. As we noted in our discussion of Exhibit 3, risk premiums were positively correlated with interest rates from 1966 through 1979, but, beginning in 1980, the relationship turned negative. A possible explanation for this change is given next.

1966–1979 Period. During this period, inflation heated up, fuel prices soared, environmental problems surfaced, and demand for electricity slowed even as expensive new generating units were nearing completion. These cost increases required offsetting rate hikes to maintain profit levels. However, political pressure, combined with administrative procedures that were not designed to deal with a volatile economic environment, led to long periods of "regulatory lag" that caused utilities' earned ROEs to decline in absolute terms and to fall far below the cost of equity. These factors combined to cause utility stockholders to experience huge losses: S&P's Electric Index dropped from a mid-1960s high of 60.90 to a mid-1970s low of 20.41, a decrease of 66.5%. Industrial stocks also suffered losses during this period, but, on average, they were only one third as severe as the utilities' losses. Similarly, investors in long-term bonds had losses, but bond losses were less than half those of utility stocks. Note also that, during this period, (i) bond investors were able to reinvest coupons and maturity payments at rising rates, whereas the earned returns on equity did not rise, and (ii) utilities were providing a rising share of their operating income to debtholders versus stockholders (interest expense/book value of debt was rising, while net income/common equity was declining). This led to a widespread belief that utility commissions would provide enough revenues to keep utilities from going bankrupt (barring a disaster), and hence to protect the bondholders, but that they would not necessarily provide enough revenues either to permit the expected rate of dividend growth to occur or, perhaps, even to allow the dividend to be maintained.

Because of these experiences, investors came to regard inflation as having a more negative effect on utility stocks than on bonds. Therefore, when fears of inflation increased, utilities' measured risk premiums

Exhibit 10. Relative Volatility* of Stocks and Bonds, 1965–1984



*Volatility is measured as the standard deviation of total returns over the last 5 years.
Source: Merrill Lynch, *Quantitative Analysis*, May/June 1984.

also increased. A regression over the period 1966–1979, using our Exhibit 2 data, produced this result:

$$RP = 0.30\% + 0.73\ R_F; \qquad r^2 = 0.48.$$
$$(0.22)$$

This indicates that a one percentage point increase in the Treasury bond rate produced, on average, a 0.73 percentage point increase in the risk premium, and hence a 1.00 + 0.73 = 1.73 percentage point increase in the cost of equity for utilities.

1980–1984 Period. The situation changed dramatically in 1980 and thereafter. Except for a few companies with nuclear construction problems, the utilities' financial situations stabilized in the early 1980s, and then improved significantly from 1982 to 1984. Both the companies and their regulators were learning to live with inflation; many construction programs were completed; regulatory lags were shortened; and in general the situation was much better for utility equity investors. In the meantime, over most of the 1980–1984 period, interest rates and bond prices fluctuated violently, both in an absolute sense and relative to common stocks. Exhibit 10 shows the volatility of corporate bonds very clearly. Over most of the eighteen-year period, stock returns were much more volatile than returns on bonds. However, that situation changed in October 1979, when the Fed began to focus on the money supply rather than on interest rates.[9]

In the 1980–1984 period, an increase in inflationary expectations has had a more adverse effect on bonds than on utility stocks. If the expected rate of inflation increases, then interest rates *will increase* and bond prices *will fall*. Thus, uncertainty about inflation translates directly into risk in the bond markets. The effect of inflation on stocks, including utility stocks, is less clear. If inflation increases, then utilities should, in theory, be able to obtain rate increases that would offset increases in operating costs and also compensate for the higher cost of equity. Thus, with "proper" regulation, utility stocks would provide a better hedge against unanticipated inflation than would bonds. This hedge did not work at all well during the 1966–1979 period, because inflation-induced increases in operating and capital costs were not offset by timely rate increases. However, as noted earlier, both the utilities and their regulators seem to have learned to live better with inflation during the 1980s.

Since inflation is today regarded as a major investment risk, and since utility stocks now seem to provide a better hedge against unanticipated inflation than do

[9]Because the standard deviations in Exhibit 10 are based on the last five years of data, even if bond returns stabilize, as they did beginning in 1982, their reported volatility will remain high for several more years. Thus, Exhibit 10 gives a rough indication of the current relative riskiness of stocks versus bonds, but the measure is by no means precise or necessarily indicative of future expectations.

bonds, the interest-rate risk inherent in bonds offsets, to a greater extent than was true earlier, the higher operating risk that is inherent in equities. Therefore, when inflationary fears rise, the perceived riskiness of bonds rises, helping to push up interest rates. However, since investors are today less concerned about inflation's impact on utility stocks than on bonds, the utilities' cost of equity does not rise as much as that of debt, so the observed risk premium tends to fall.

For the 1980–1984 period, we found the following relationship (see Exhibit 6):

$$RP = 12.53\% - \underset{(0.05)}{0.63}\ R_{Fi} \qquad r^2 = 0.73.$$

Thus, a one percentage point increase in the T-bond rate, on average, caused the risk premium to fall by 0.63%, and hence it led to a 1.00 − 0.63 = 0.37 percentage point increase in the cost of equity to an average utility. This contrasts sharply with the pre-1980 period, when a one percentage point increase in interest rates led, on average, to a 1.73 percentage point increase in the cost of equity.

Summary and Implications

We began by reviewing a number of earlier studies. From them, we concluded that, for cost of capital estimation purposes, risk premiums must be based on expectations, not on past realized holding period returns. Next, we noted that expectational risk premiums may be estimated either from surveys, such as the ones Charles Benore has conducted, or by use of DCF techniques. Further, we found that, although growth rates for use in the DCF model can be either developed from time-series data or obtained from security analysts, analysts' growth forecasts are more reflective of investors' views, and, hence, in our opinion are preferable for use in risk-premium studies.

Using analysts' growth rates and the DCF model, we estimated risk premiums over several different periods. From 1966 to 1984, risk premiums for both electric utilities and industrial stocks varied widely from year to year. Also, during the first half of the period, the utilities had smaller risk premiums than the industrials, but after the mid-1970s, the risk premiums for the two groups were, on average, about equal.

The effects of changing interest rates on risk premiums shifted dramatically in 1980, at least for the utilities. From 1965 through 1979, inflation generally had a more severe adverse effect on utility stocks than on bonds, and, as a result, an increase in inflationary expectations, as reflected in interest rates, caused an increase in equity risk premiums. However, in 1980 and thereafter, rising inflation and interest rates increased the perceived riskiness of bonds more than that of utility equities, so the relationship between interest rates and utility risk premiums shifted from positive to negative. Earlier, a 1.00 percentage point increase in interest rates had led, on average, to a 1.73% increase in the utilities' cost of equity, but after 1980 a 1.00 percentage point increase in the cost of debt was associated with an increase of only 0.37% in the cost of equity.

Our study also has implications for the use of the CAPM to estimate the cost of equity for utilities. The CAPM studies that we have seen typically use either Ibbotson-Sinquefield or similar historic holding period returns as the basis for estimating the market risk premium. Such usage implicitly assumes (i) that *ex post* returns data can be used to proxy *ex ante* expectations and (ii) that the market risk premium is relatively stable over time. Our analysis suggests that neither of these assumptions is correct; at least for utility stocks, *ex post* returns data do not appear to be reflective of *ex ante* expectations, and risk premiums are volatile, not stable.

Unstable risk premiums also make us question the FERC and FCC proposals to estimate a risk premium for the utilities every two years and then to add this premium to a current Treasury bond rate to determine a utility's cost of equity. Administratively, this proposal would be easy to handle, but risk premiums are simply too volatile to be left in place for two years.

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Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts

Robert S. Harris and Felicia C. Marston

Robert S. Harris is the C. Stewart Sheppard Professor of Business at the Darden Graduate School of Business at the University of Virginia, Charlottesville, Virginia. Felicia C. Marston is an Assistant Professor of Commerce at the McIntire School of Commerce, University of Virginia, Charlottesville, Virginia.

■ One of the most widely used concepts in finance is that shareholders require a risk premium over bond yields to bear the additional risks of equity investments. While models such as the two-parameter capital asset pricing model (CAPM) or arbitrage pricing theory offer explicit methods for varying risk premia across securities, the models are invariably linked to some underlying market (or factor-specific) risk premium. Unfortunately, the theoretical models provide limited practical advice on establishing empirical estimates of such a benchmark market risk premium. As a result, the typical advice to practitioners is to estimate the market risk premium based on historical realizations of share and bond returns (see Brealey and Myers [3]).

In this paper, we present estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts. We update, through 1991, earlier work which, due to data availability, was restricted to the period 1982-1984 (Harris [12]). Using stronger tests, we also reexamine the efficacy of using such an expectational approach as an alternative to the use of historical averages. Using the S&P 500 as a proxy for the market portfolio, we find an average market risk premium (1982-1991) of 6.47% above yields on long-term U.S. government bonds and 5.13% above yields on corporate bonds. We also find that required returns for individual stocks vary directly with their risk (as proxied by beta) and that the market risk premium varies over time. In particular, the equity market premium over government bond yields is higher in low interest rate environments and when there is a larger spread between corporate and government bond yields. These findings show that, in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.

Section I provides background on the estimation of equity required returns and a brief discussion of related

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