BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-170485

DOCKET NO. UG-170486

WORKPAPERS

ADRIEN M. MCKENZIE

REPRESENTING AVISTA CORPORATION

ADRIEN M. MCKENZIE REBUTTAL WORKPAPERS

INDEX

ADRIEN M. MCKENZIE WORKPAPERS

INDEX

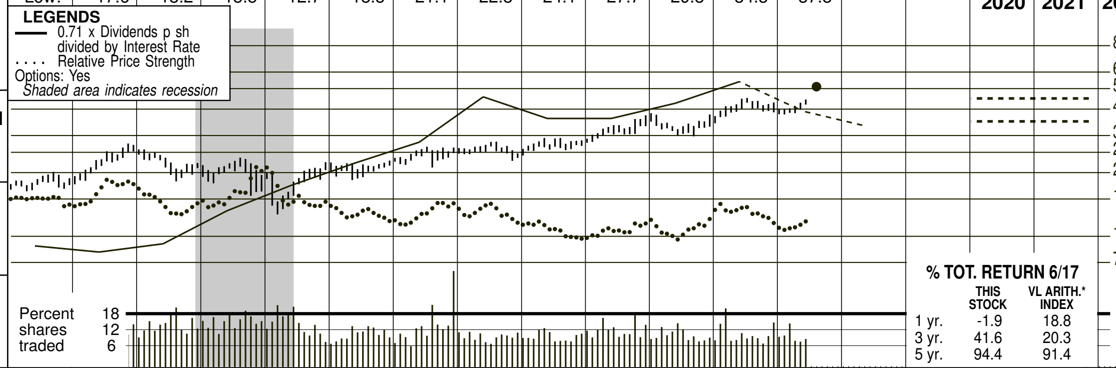
AVISTA CORP. NYSE-AVA

RECENT PRICE 51.07 [F] | P/E RATIO 25.5 (Trailing: 23.2, Median: 16.0) | RELATIVE P/E RATIO 1.29 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS – Suspended 7/28/17
SAFETY 2 Raised 5/7/10
TECHNICAL – Suspended 7/28/17
BETA .70 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:			27.5	25.8	23.6	22.4	22.8	26.5	28.0	29.3	37.4	38.3	45.2	44.4			
Low:			17.6	18.2	15.5	12.7	18.5	21.1	22.8	24.1	27.7	29.8	34.3	37.8			

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(-10%)	Nil
Low	35	(-30%)	-5%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	9	0	0	0	11	12	0	0	9
to Sell	1	0	0	0	0	0	7	0	2

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	119	127	142
to Sell	101	107	106
Hld's(000)	44354	44869	57014

% TOT. RETURN 6/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.9	18.8
3 yr.	41.6	20.3
5 yr.	94.4	91.4

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
126.17	20.41	23.24	23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	22.47	*22.20*	*22.20*	Revenues per sh	*23.00*
2.71	2.19	2.63	2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	*5.25*	*5.40*	"Cash Flow" per sh	*6.00*
1.20	.67	1.02	.73	.92	1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	2.15	*2.00*	*2.05*	Earnings per sh [A]	*2.25*
.48	.48	.49	.52	.55	.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	*1.43*	*1.49*	Div'd Decl'd per sh [B] ■	*1.67*
5.92	1.74	2.21	2.47	3.23	3.14	4.04	4.09	3.86	3.64	4.20	4.61	5.05	5.47	6.46	6.34	*6.25*	*6.10*	Cap'l Spending per sh	*6.25*
15.12	14.84	15.54	15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	25.69	*26.60*	*27.30*	Book Value per sh [C]	*29.50*
47.63	48.04	48.34	48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	64.19	*66.00*	*67.50*	Common Shs Outst'g [D]	*72.00*
13.7	19.3	13.8	24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.70	1.05	.79	1.29	1.03	.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	*Value Line*		Relative P/E Ratio	*1.10*
2.9%	3.7%	3.5%	2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 3/31/17
Total Debt $1838.0 mill. **Due in 5 Yrs** $548.7 mill.
LT Debt $1729.7 mill. **LT Interest** $80.0 mill.
Incl. $51.5 mill. debt to affiliated trusts; $62.2 mill. capitalized leases.
(LT interest earned: 3.5x)
Pension Assets-12/16 $540.9 mill. **Oblig** $666.5 mill.
Pfd Stock None

Common Stock 64,388,095 shs. as of 4/30/17

MARKET CAP: $3.3 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
1417.8	1676.8	1512.6	1558.7	1619.8	1547.0	1618.5	1472.6	1484.8	1442.5	*1465*	*1500*	Revenues ($mill)	*1650*
38.5	73.6	87.1	92.4	100.2	78.2	111.1	114.2	118.1	137.2	*130*	*135*	Net Profit ($mill)	*160*
38.7%	38.3%	34.3%	35.0%	35.4%	34.4%	36.0%	37.6%	36.3%	36.3%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
22.4%	14.0%	4.2%	4.0%	5.2%	8.3%	8.8%	11.1%	10.1%	8.1%	*9.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
41.0%	48.1%	50.9%	51.6%	51.4%	50.8%	51.4%	51.0%	50.0%	51.2%	*47.0%*	*50.0%*	Long-Term Debt Ratio	*45.0%*
59.0%	51.9%	49.1%	48.4%	48.6%	49.2%	48.6%	49.0%	50.0%	48.8%	*53.0%*	*50.0%*	Common Equity Ratio	*55.0%*
1548.9	1919.5	2139.0	2325.3	2439.9	2561.2	2669.7	3027.3	3060.3	3379.0	*3325*	*3670*	Total Capital ($mill)	*3875*
2351.3	2492.2	2607.0	2714.2	2860.8	3023.7	3202.4	3620.0	3898.6	4147.5	*4345*	*4530*	Net Plant ($mill)	*5050*
5.2%	5.8%	5.5%	5.4%	5.5%	4.3%	5.4%	4.9%	5.1%	5.3%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
4.2%	7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	*7.5%*	*7.5%*	Return on Shr. Equity	*7.5%*
4.2%	7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	*7.5%*	*7.5%*	Return on Com Equity [E]	*7.5%*
.8%	3.7%	4.1%	3.3%	3.1%	.8%	2.9%	2.4%	2.3%	3.0%	*2.0%*	*2.0%*	Retained to Com Eq	*2.0%*
82%	50%	51%	60%	64%	88%	66%	69%	70%	64%	*71%*	*72%*	All Div'ds to Net Prof	*74%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+.8	-2.0	-1.2
Avg. Indust. Use (MWH)	1349	1339	1314
Avg. Indust. Revs. per KWH (¢)	5.93	6.17	6.09
Capacity at Peak (Mw)	2594	NA	NA
Peak Load, Winter (Mw)	2223	NA	NA
Annual Load Factor (%)	64.0	NA	NA
% Change Customers (yr-end)	+5.5	+1.3	+.6
Fixed Charge Cov. (%)	322	315	333

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-1.5%	-3.5%	*Nil*
"Cash Flow"	4.5%	4.0%	*3.5%*
Earnings	6.5%	3.5%	*2.5%*
Dividends	9.5%	6.5%	*4.0%*
Book Value	4.0%	4.5%	*3.0%*

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	446.6	312.6	301.6	411.8	1472.6
2015	446.5	337.3	313.7	387.3	1484.8
2016	418.2	318.8	303.4	402.1	1442.5
2017	436.5	*320*	*305*	*403.5*	*1465*
2018	*430*	*330*	*320*	*420*	*1500*

EARNINGS PER SHARE [A]

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.79	.43	.16	.48	1.84
2015	.74	.40	.21	.54	1.89
2016	.92	.43	.19	.62	2.15
2017	.96	*.39*	*.15*	*.50*	*2.00*
2018	*.85*	*.45*	*.15*	*.60*	*2.05*

QUARTERLY DIVIDENDS PAID [B] ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.305	.305	.305	.305	1.22
2014	.3175	.3175	.3175	.3175	1.27
2015	.33	.33	.33	.33	1.32
2016	.3425	.3425	.3425	.3425	1.37
2017	.3575	.3575			

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 392,000 electric, 340,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 35%; commercial, 31%; industrial, 11%; wholesale, 11%; other, 13%. Generating sources: hydro, 32%; gas & coal, 30%; purchased, 38%. Fuel costs: 38% of revs. '16 reported deprec. rate (Avista Utilities): 3.1%. Has 2,000 employees. Chairman, President & CEO: Scott L. Morris. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

Avista has accepted a takeover offer. Hydro One, a Canadian company, has agreed to pay US$53 in cash for each share of Avista. The transaction requires the approval of Avista's stockholders, the regulatory commissions in Washington, Idaho, Oregon, Alaska, and Montana, plus the Federal Energy Regulatory Commission. The companies expect the deal to be completed in the second half of 2018.

We advise stockholders to sell their shares on the open market. The offer is generous, at more than 26 times estimated 2017 earnings. However, with the need for regulatory approvals from five state commissions, there is a good deal of regulatory uncertainty. Accordingly, stockholders can avoid downside risk by selling now. The stock's Timeliness rank is suspended due to the takeover agreement.

Avista filed a multiyear rate case in Washington. First, the utility sought a $15.0 million adjustment to reflect increased power costs, effective on September 1st. Then, it requested electric increases of $61.4 million on May 1, 2018, $14.0 million on May 1, 2019, and $14.4 million on May 1, 2020, along with gas hikes of $8.3 million in year one, $4.2 million in year two, and $4.4 million in year three. This is based on a 9.9% return on a 50% common-equity ratio.

We expect a partial earnings recovery in 2018, after a decline this year. The lack of rate relief in Washington will hurt 2017 profits by an estimated $0.20-$0.30 a share. Assuming reasonable orders in the pending rate cases, we think Avista's earnings will exceed $2.00 a share in 2018.

Avista filed a multiyear rate case in Idaho. The utility sought electric hikes of $18.6 million and $9.9 million at the start of 2018 and 2019, respectively, and gas increases of $3.5 million next year and $2.1 million in 2019. This is based on a 9.9% return on a 50% common-equity ratio.

Other rate cases are pending. In Oregon, Avista reached a settlement calling for a $3.5 million gas rate increase, based on a 9.4% return on a 50% common-equity ratio. New rates would take effect on October 1st. In Alaska, the company is seeking an electric hike of $2.8 million, based on a 13.8% return on a 58% common-equity ratio. A ruling is due by February 8th.

Paul E. Debbas, CFA *July 28, 2017*

(A) Dil. EPS. Excl. nonrec. gain (losses): '02, (9¢); '03, (3¢); '14, 9¢; gains (losses) on disc. ops.: '01, ($1.00); '02, 2¢; '03, (10¢); '14, $1.17; '15, 8¢. Next earnings report due early Aug. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinv. avail. (C) Incl. def'd chgs. In '16: $11.33/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WA in '16: 9.5%; in ID in '17: 9.5%; in OR in '15: 9.5%; earn. on avg. com. eq., '16: 8.6%. Regul. Clim.: WA, Avg.; ID, Above Avg. (F) Price as of 9:30 AM (EDT) on 7/20/17.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	75

BLACK HILLS CORP. NYSE-BKH

RECENT PRICE **67.60** | P/E RATIO **19.0** (Trailing: 21.3 Median: 18.0) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **2.8%** | VALUE LINE

TIMELINESS	3	Lowered 9/8/17
SAFETY	2	Raised 5/1/15
TECHNICAL	2	Raised 10/6/17

BETA .90 (1.00 = Market)

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+5%)	4%
Low	55	(-20%)	-2%

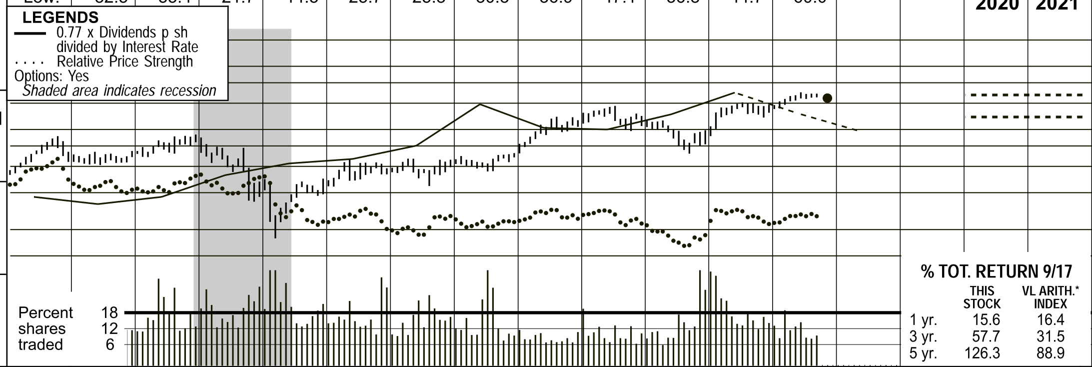
Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	9	6	12	9	6	6	9	6	6
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	129	121	143
to Sell	103	100	92
Hld's(000)	48931	60019	59838

High:	37.9	45.4	44.0	28.0	34.5	34.8	37.0	55.1	62.1	53.4	64.6	72.0
Low:	32.5	35.4	21.7	14.5	25.7	25.8	30.3	36.9	47.1	36.8	44.7	60.0



Target Price Range 2020 | 2021 | 2022

% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.6	16.4
3 yr.	57.7	31.5
5 yr.	126.3	88.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
57.96	15.74	35.17	34.54	41.97	19.69	18.41	26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	29.47	*31.95*	*29.90*	Revenues per sh	*33.25*
5.27	4.93	4.26	4.46	4.81	5.04	5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	6.28	*7.30*	*7.15*	"Cash Flow" per sh	*8.50*
3.42	2.33	1.84	1.74	2.11	2.21	2.68	.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	2.63	*3.50*	*3.70*	Earnings per sh A	*4.25*
1.12	1.16	1.20	1.24	1.28	1.32	1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.62	1.68	*1.78*	*1.88*	Div'd Decl'd per sh B ■	*2.20*
14.07	8.65	2.80	2.80	4.18	9.24	6.92	8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	8.89	*6.55*	*6.10*	Cap'l Spending per sh	*6.75*
18.95	19.66	21.72	22.43	22.29	23.68	25.66	27.19	27.84	28.02	27.53	27.88	29.39	30.80	28.63	30.25	*31.80*	*35.30*	Book Value per sh C	*40.75*
26.89	26.93	32.30	32.48	33.16	33.37	37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	53.38	*54.00*	*60.25*	Common Shs Outst'g D	*61.00*
11.4	12.5	15.9	17.1	17.3	15.8	15.0	NMF	9.9	18.1	31.1	17.1	18.2	19.0	16.1	22.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.58	.68	.91	.90	.92	.85	.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	*Value Line*		Relative P/E Ratio	*.95*
2.9%	4.0%	4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%	3.5%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $3274.0 mill. **Due in 5 Yrs** $989.4 mill.
LT Debt $3160.3 mill. **LT Interest** $125.4 mill.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $6.7 mill.

Pension Assets-12/16 $364.7 mill. **Oblig** $440.2 mill.

Pfd Stock None

Common Stock 53,475,190 shs. as of 7/31/17

MARKET CAP: $3.6 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
695.9	1005.8	1269.6	1307.3	1272.2	1173.9	1275.9	1393.6	1304.6	1573.0	*1725*	*1800*	Revenues ($mill)	*2025*
100.1	6.8	89.7	64.6	40.4	86.9	115.8	128.8	128.3	140.3	*190*	*215*	Net Profit ($mill)	*260*
31.3%	33.1%	30.7%	26.4%	31.1%	35.5%	34.7%	33.7%	35.8%	25.1%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
14.8%	173.2%	20.1%	28.0%	65.0%	5.4%	2.4%	2.4%	2.7%	5.3%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
36.8%	32.3%	48.4%	51.9%	51.4%	43.2%	51.6%	47.9%	56.0%	66.5%	*67.5%*	*61.0%*	Long-Term Debt Ratio	*60.0%*
63.2%	67.7%	51.6%	48.1%	48.6%	56.8%	48.4%	52.1%	44.0%	33.5%	*32.5%*	*39.0%*	Common Equity Ratio	*40.0%*
1534.2	1551.8	2100.7	2286.3	2489.7	2171.4	2704.7	2643.6	3332.7	4825.8	*5280*	*5435*	Total Capital ($mill)	*6250*
1823.5	2022.2	2160.7	2495.4	2789.6	2742.7	2990.3	3239.4	3259.1	4469.0	*4620*	*4770*	Net Plant ($mill)	*5275*
7.9%	1.6%	5.9%	4.4%	3.3%	5.5%	5.5%	6.1%	4.9%	4.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
10.3%	.7%	8.3%	5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	8.7%	*11.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
10.3%	.7%	8.3%	5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	8.7%	*11.0%*	*10.0%*	Return on Com Equity E	*10.5%*
5.1%	NMF	3.2%	.7%	NMF	1.8%	3.7%	4.3%	3.8%	3.3%	*5.5%*	*5.0%*	Retained to Com Eq	*5.0%*
50%	NMF	62%	87%	NMF	75%	58%	54%	57%	62%	*51%*	*51%*	All Div'ds to Net Prof	*51%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.9	+4.5	+3.0
Avg. Indust. Use (MWH)	13055	15552	17321
Avg. Indust. Revs. per KWH (¢)	7.97	8.02	7.80
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	992	1028	1086
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+.6
Fixed Charge Cov. (%)	357	324	236

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-1.0%	-2.0%	*2.5%*
"Cash Flow"	2.5%	5.0%	*6.0%*
Earnings	3.5%	11.0%	*7.5%*
Dividends	2.5%	2.5%	*5.0%*
Book Value	2.5%	1.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	460.2	283.2	272.1	378.1	1393.6
2015	442.0	272.2	272.1	318.3	1304.6
2016	450.0	325.4	333.8	463.8	1573.0
2017	554.0	348.0	*348*	*475*	*1725*
2018	*575*	*365*	*365*	*495*	*1800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.08	.44	.60	.76	2.89
2015	1.07	.55	.58	.63	2.83
2016	.94	.31	.41	.97	2.63
2017	1.39	.40	*.71*	*1.00*	*3.50*
2018	*1.45*	*.45*	*.75*	*1.05*	*3.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.38	.38	.38	.38	1.52
2014	.39	.39	.39	.39	1.56
2015	.405	.405	.405	.405	1.62
2016	.42	.42	.42	.42	1.68
2017	.445	.445	.445		

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 209,000 electric customers in CO, SD, WY and MT, and 1 million gas customers in NE, IA, KS, CO, WY, and AR. Mines coal & has gas & oil E&P business. Acq'd Cheyenne Light 1/05; utility ops. from Aquila 7/08; SourceGas 2/16. Discont. telecom in '05; oil marketing in '06; gas marketing in '11. Electric rev. breakdown: res'l, 31%; comm'l, 38%; ind'l, 17%; other, 14%. Generating sources: coal, 33%; other, 7%; purchased, 60%. Fuel costs: 32% of revs. '16 deprec. rate: 3.0%. Has 2,800 employees. Chairman & CEO: David R. Emery. Pres. & COO: Linn Evans. Inc.: SD. Address: P.O. Box 1400, 625 Ninth St., Rapid City, SD 57701. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills' earnings will probably rise materially in 2017. A year ago, the company incurred expenses of $0.56 a share arising from the acquisition of SourceGas in mid-February. These costs were just $0.02 a share in the first half of 2017. In addition, the company benefited from having SourceGas for all of the seasonally strong first quarter. Our profit estimate is within Black Hills' guidance of $3.45-$3.60 a share.

The company is trying to sell gas and oil exploration and production assets. Low commodity prices in recent years have hurt this business, which is likely to lose $0.10-$0.15 a share this year. (Black Hills took sizable writedowns in 2015 and 2016.) It had intended to retain some properties for use in a proposed program to place gas reserves in the rate base, but with gas prices remaining low, such a proposal is not likely to win regulatory approval. Management has not stated that it is trying to sell the entire operation, but is likely to announce its plans within the next few months.

Black Hills will likely improve its bottom line next year. Additional synergies from the SourceGas deal, normal utility growth, and a smaller loss from the gas and oil operation should help.

Black Hills is about to become more active in the regulatory arena. In recent years, the company's utilities have filed few rate cases because there was little need to do so. The most recent application, in Colorado, did not go well. The commission granted the utility just $1.2 million of the $8.9 million the company had requested, so Black Hills appealed the order to the district court. As the cost reductions arising from the SourceGas purchase diminish, Black Hills will start filing rate cases—as many as 10 within the next five years. A gas application in Arkansas is expected later this quarter.

Black Hills stock is priced expensively. The dividend yield is below the utility average, and the recent quotation is near the top end of our 3- to 5-year Target Price Range. We think this reflects some takeover speculation; mid-cap utilities have been buyout targets in recent years. But we advise against purchasing the stock in the hope of a takeover offer.

Paul E. Debbas, CFA *October 27, 2017*

(A) Dil. EPS. Excl. nonrec. gains (losses): '08, ($1.55); '09, (28¢); '10, 10¢; '12, 4¢; '15, ($3.54); '16, ($1.26); gains (losses) on disc. ops.: '06, 21¢; '07, (4¢); '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢). '14 EPS don't sum due to rounding. Next egs. due early Nov. (B) Div'ds paid early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '16: $29.12/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '15: none specified; in CO in '17: 9.37%; earned on avg. com. eq., '16: 8.7%. Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	65
Earnings Predictability	50

EDISON INTERNAT'L NYSE-EIX

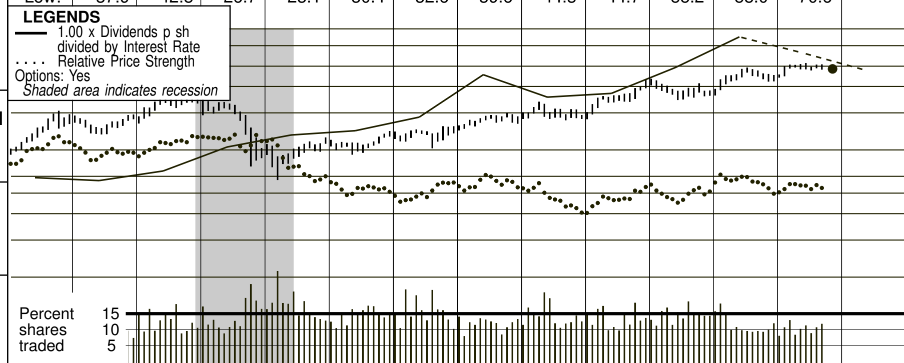
RECENT PRICE 77.60 | P/E RATIO 18.3 (Trailing: 18.5 Median: 12.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Lowered 8/11/17
SAFETY 2 Raised 5/3/13
TECHNICAL 2 Raised 10/6/17
BETA .65 (1.00 = Market)

High:	47.2	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7	69.6	78.7	82.8
Low:	37.9	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58.0	70.6

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+20%)	8%
Low	70	(-10%)	1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	10	9	2	2	3	2	0	1
to Sell	0	0	1	1	1	1	2	0	1

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	273	252	299
to Sell	243	273	236
Hld's(000)	270585	292772	290101

Percent shares traded 15 10 5

% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.9	16.4
3 yr.	49.9	31.5
5 yr.	92.5	88.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	**37.60**	**39.45**	Revenues per sh	**45.50**
4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	**11.05**	**11.55**	"Cash Flow" per sh	**13.50**
1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	**4.25**	**4.40**	Earnings per sh A	**5.25**
--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	**2.21**	**2.36**	Div'd Decl'd per sh B ■	**2.90**
2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	**13.10**	**15.40**	Cap'l Spending per sh	**16.00**
10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	**38.30**	**39.75**	Book Value per sh C	**44.75**
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	**325.81**	**325.81**	Common Shs Outst'g D	**325.81**
10.0	7.8	7.0	37.6	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	*Bold figures are*		Avg Ann'l P/E Ratio	**15.5**
.51	.43	.40	1.99	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	*Value Line*		Relative P/E Ratio	**.95**
--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	*estimates*		Avg Ann'l Div'd Yield	**3.6%**

CAPITAL STRUCTURE as of 6/30/17
Total Debt $12809 mill. **Due in 5 Yrs** $3066 mill.
LT Debt $11662 mill. **LT Interest** $583 mill.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $393 mill.
Pens. Assets-12/16 $3388 mill. **Oblig** $4284 mill.
Pfd Stock $2654 mill. **Pfd Div'd** $123 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 7/25/17**
MARKET CAP: $25 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
13113	14112	12374	12409	12760	11862	12581	13413	11524	11869	**12250**	**12850**	Revenues ($mill)	**14800**
1151.0	1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	1539.0	1480.0	1422.0	**1520**	**1570**	Net Profit ($mill)	**1845**
27.3%	30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	22.4%	6.6%	11.1%	**18.0%**	**18.0%**	Income Tax Rate	**18.0%**
8.2%	8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	5.8%	8.0%	6.8%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**6.0%**
49.1%	51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	44.1%	45.0%	41.8%	**43.5%**	**46.0%**	Long-Term Debt Ratio	**46.0%**
46.0%	44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	47.2%	46.7%	49.2%	**48.0%**	**46.5%**	Common Equity Ratio	**47.0%**
18375	21374	21185	23861	24773	20422	21516	23216	24352	24362	**25950**	**27925**	Total Capital ($mill)	**31000**
17403	18969	21966	24778	32116	30273	30455	32981	35085	37000	**39075**	**41775**	Net Plant ($mill)	**49400**
8.3%	7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	7.7%	7.1%	6.9%	**7.0%**	**6.5%**	Return on Total Cap'l	**7.0%**
12.3%	12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	11.9%	11.1%	10.0%	**10.5%**	**10.5%**	Return on Shr. Equity	**11.0%**
13.0%	12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	13.0%	12.0%	10.8%	**11.0%**	**11.0%**	Return on Com Equity E	**12.0%**
9.2%	8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	8.8%	7.2%	5.6%	**5.5%**	**5.0%**	Retained to Com Eq	**5.5%**
33%	35%	41%	40%	43%	32%	40%	37%	44%	53%	**55%**	**57%**	All Div'ds to Net Prof	**58%**

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.1	-1.4	-2.6
Avg. Indust. Use (MWH)	788	703	664
Avg. Indust. Revs. per KWH (¢)	8.86	9.07	6.51
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	23055	23079	23091
Annual Load Factor (%)	52.3	52.2	50.7
% Change Customers (yr-end)	+.6	+.6	+.5
Fixed Charge Cov. (%)	306	247	246

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	.5%	-.5%	3.0%
"Cash Flow"	5.5%	4.0%	4.5%
Earnings	5.5%	5.0%	4.0%
Dividends	6.0%	6.5%	9.0%
Book Value	5.5%	2.5%	4.0%

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	2926	3016	4356	3115	13413
2015	2512	2908	3763	2341	11524
2016	2440	2777	3767	2885	11869
2017	2463	2965	**3872**	**2950**	**12250**
2018	**2600**	**3100**	**4050**	**3100**	**12850**

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.61	1.07	1.51	1.15	4.33
2015	.91	1.15	1.15	.94	4.15
2016	.85	.86	1.27	.96	3.94
2017	1.11	.85	**1.34**	**.95**	**4.25**
2018	**1.10**	**.90**	**1.40**	**1.00**	**4.40**

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.3375	.3375	.3375	.3375	1.35
2014	.355	.355	.355	.355	1.42
2015	.4175	.4175	.4175	.4175	1.67
2016	.48	.48	.48	.48	1.92
2017	.5425	.5425	.5425		

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.1 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 6%; nuclear, 6%; hydro, 5%; purchased, 83%. Fuel costs: 38% of revs. '16 reported depr. rate: 3.8%. Has 12,400 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International's utility subsidiary is awaiting an order on its general rate case. Southern California Edison is requesting electric rate increases of $196 million (2.5%) in 2018, $480 million (3.8%) in 2019, and $556 million (5.1%) in 2020. The California Public Utilities Commission's (CPUC) Office of Ratepayer Advocates (ORA) is recommending a boost of just $14 million next year. An intervenor group is proposing a hike of $129 million. The utility's filing proposes spending of $14.8 billion over the 2018-2020 period, including $1.8 billion to modernize the electric grid. The latter spending is new, compared with previous rate cases, and is controversial. An administrative law judge will put forth a proposed decision (probably as early as the first half of November) before the CPUC issues its order. Even if this order comes after the end of 2017, it will be retroactive to the start of 2018.

Another regulatory matter is pending. In 2015, SCE reached a settlement regarding the closed San Onofre nuclear station. As a result, the utility's customers received nearly $1.6 billion in refunds and credits. However, the ORA and an intervenor said this matter should be reopened due to *ex parte* communications between SCE and former CPUC commissioners. The parties were unable to reach an agreement to present to the CPUC, so the regulators will take the next step. Additional refunds and/or customer credits are possible. There is no timetable for resolving this matter.

The Edison Energy nonutility subsidiary is a drag on earnings. This will lose an estimated $0.11 a share this year (based on the company's earnings guidance of $4.13-$4.33 a share). This includes a $0.03-a-share writedown of the company's solar business, which Edison Energy is trying to sell. This unit will focus on energy services instead. Its goal is to reach the break-even point by the end of 2019.

This stock's most noteworthy feature is its good dividend growth potential. We look for a $0.15-a-share (6.9%) hike in the annual payout at the board meeting in December. Even with this estimated increase, however, the yield is low for a utility, and 3- to 5-year total return potential is unspectacular.

Paul E. Debbas, CFA *October 27, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); gains (loss) from disc. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '16, 3¢. '14 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '16: $22.88/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.45%; earned on avg. com. eq., '16: 11.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	60

EL PASO ELECTRIC NYSE-EE

RECENT PRICE 57.15 | P/E RATIO 22.0 (Trailing: 20.6 / Median: 15.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 1 Raised 9/22/17
SAFETY 2 Raised 5/11/07
TECHNICAL 3 Raised 9/29/17
BETA .80 (1.00 = Market)

High:	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3	48.8	58.7
Low:	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2	44.7

2020-22 PROJECTIONS

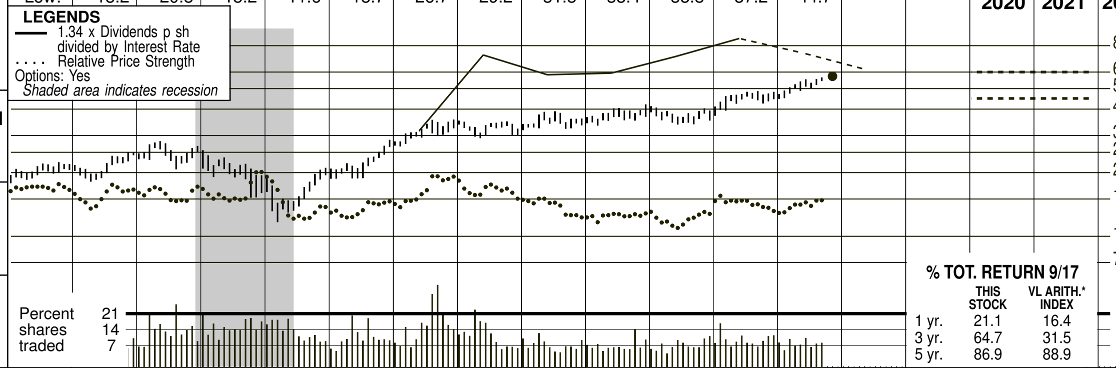
	Price	Gain	Ann'l Total Return
High	60	(+5%)	4%
Low	45	(-20%)	-2%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	0	0	3	9	3	4	0
to Sell	1	0	0	1	0	0	1	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	104	107	117
to Sell	75	72	78
Hld's(000)	39292	44613	45099



% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.1	16.4
3 yr.	64.7	31.5
5 yr.	86.9	88.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	21.89	*22.80*	*23.35*	Revenues per sh	*25.00*
3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	5.98	*6.30*	*6.50*	"Cash Flow" per sh	*7.25*
1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	2.39	*2.60*	*2.65*	Earnings per sh A	*3.00*
--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	1.23	*1.32*	*1.42*	Div'd Decl'd per sh B	*1.75*
1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	7.03	*6.35*	*5.65*	Cap'l Spending per sh	*7.00*
9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	26.52	*27.75*	*29.00*	Book Value per sh C	*32.75*
49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	40.52	*40.60*	*40.70*	Common Shs Outst'g D	*41.00*
11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.92	.98	*Value Line*		Relative P/E Ratio	*1.05*
--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*
						877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	849.9	886.9	*925*	*950*	Revenues ($mill)	*1025*
						74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	81.9	96.8	*105*	*110*	Net Profit ($mill)	*125*
						31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	29.9%	35.8%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
						15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	27.5%	17.6%	*9.0%*	*11.0%*	AFUDC % to Net Profit	*14.0%*
						49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.7%	52.7%	*51.5%*	*52.5%*	Long-Term Debt Ratio	*51.0%*
						50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.3%	47.3%	*48.5%*	*47.5%*	Common Equity Ratio	*49.0%*
						1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2150.8	2269.9	*2325*	*2475*	Total Capital ($mill)	*2725*
						1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2695.5	2821.2	*2930*	*3005*	Net Plant ($mill)	*3325*
						7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.3%	5.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
						11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
						11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	*9.5%*	*9.5%*	Return on Com Equity E	*9.5%*
						11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.4%	4.4%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
						--	--	--	--	26%	43%	47%	49%	57%	51%	*50%*	*53%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $1457.9 mill. **Due in 5 Yrs** $307.0 mill.
LT Debt $1195.7 mill. **LT Interest** $72.3 mill.
(LT interest earned: 3.2x)

Pension Assets-12/16 $269.8 mill. **Oblig** $337.8 mill.

Pfd Stock None

Common Stock 40,591,704 shs. as of 7/31/17

MARKET CAP: $2.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-1.6	+2.3	+.1
Avg. Indust. Use (MWH)	21505	21687	21036
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1879	2055	2080
Peak Load, Summer (Mw)	1766	1794	1892
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.4	+1.6
Fixed Charge Cov. (%)	251	218	267

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	3.0%	1.0%	*2.0%*
"Cash Flow"	6.0%	3.0%	*3.5%*
Earnings	9.5%	2.0%	*5.0%*
Dividends	--	--	*7.0%*
Book Value	8.0%	7.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	185.5	251.8	283.6	196.6	917.5
2015	163.8	219.5	289.7	176.9	849.9
2016	157.8	217.9	323.2	188.0	886.9
2017	171.3	251.8	*296.9*	*205*	*925*
2018	*175*	*260*	*315*	*200*	*950*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.11	.75	1.30	.11	2.27
2015	.09	.52	1.40	.02	2.03
2016	d.14	.55	1.84	.14	2.39
2017	d.10	.89	*1.50*	*.31*	*2.60*
2018	*d.10*	*.75*	*1.80*	*.20*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016	.295	.31	.31	.31	1.23
2017	.31	.335	.335		

BUSINESS: El Paso Electric Company (EPE) provides electric service to 416,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 49%; gas, 34%; coal, 2%; purchased & other, 15%. Fuel costs: 26% of revenues. '16 reported depreciation rate: 2.3%. Has about 1,100 employees. Chairman: Charles A. Yamarone. President & CEO: Mary E. Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, TX 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company has reached a settlement of its general rate case in Texas. The utility had sought an increase of $39.2 million, based on a 10.5% return on a 48.35% common-equity ratio. It settled for a hike of $14.5 million, based on a 9.65% return on the same common-equity ratio. In addition, beginning in 2019 EPE will be able to file for recovery of higher transmission and distribution costs through an annual regulatory mechanism (instead of having to recoup these through a general rate case). The settlement, if approved by the Texas commission, will enable Units 3 and 4 of a gas-fired generating station to be placed in the rate base. A ruling is expected this quarter. New tariffs will be retroactive to July 18, 2017. Because fourth-quarter profits will include revenues that are retroactive to the third period, the December-quarter tally will be higher than usual in what is normally a seasonally weak period. Our estimates are based on adoption of the settlement.

Once the utility receives a decision in Texas, it will consider filing a rate case in New Mexico. EPE's last order there, in July of 2016, didn't go well. The company filed for an increase of $6.4 million, but was granted just $1.1 million. EPE won't necessarily put forth an application in 2018, but is required to do so by July of 2019.

We have raised our 2017 earnings estimate by $0.15 a share. June-quarter profits were better than we expected due to hotter-than-normal weather and an $0.08-a-share award for the performance of the Palo Verde nuclear plant. Although this will make the second-quarter earnings comparison difficult in 2018, we still look for the bottom line to advance for the full year thanks to a full year's effect of higher rates in Texas. Above-average (and rising) customer growth is another positive factor.

This stock is timely, but its dividend yield does not stand out among utilities. The yield is about a percentage point below the industry mean, and isn't much higher than the median of all dividend-paying equities under our coverage. With the recent price near the upper end of our 2020-2022 Target Price Range, total return potential is virtually zero.

Paul E. Debbas, CFA *October 27, 2017*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't sum to full-year total due to rounding. Next earnings report due early Nov. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '16: $118.9 mill., $2.93/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '16: 9.48%; earned on avg. com. eq., '16: 9.3%. Regulatory Climate: TX, Average; NM, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	75

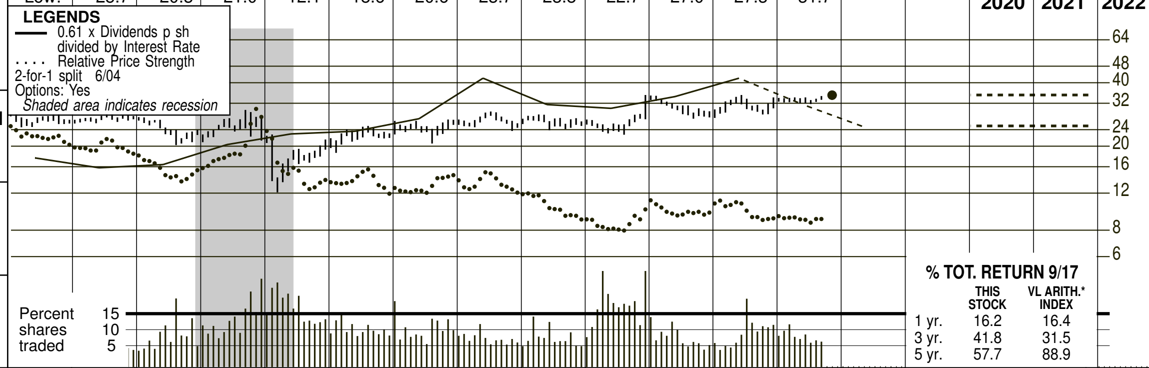
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
34.89	21.5	(Trailing: 15.5 Median: 18.0)	1.07	3.6%	VALUE LINE

TIMELINESS 4 Lowered 6/16/17
SAFETY 2 Raised 11/2/12
TECHNICAL 2 Raised 9/29/17
BETA .70 (1.00 = Market)

High:	28.9	27.5	29.8	22.7	25.0	26.8	29.2	28.3	35.0	34.9	35.0	34.9
Low:	25.7	20.3	21.0	12.1	18.6	20.6	23.7	23.8	22.7	27.0	27.3	31.7

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(Nil)	4%
Low	25	(-30%)	-3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	6	0	0	0	0	8	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	139	131	123
to Sell	100	111	103
Hld's(000)	50087	61889	60992

% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.2	16.4
3 yr.	41.8	31.5
5 yr.	57.7	88.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
24.26	22.46	23.49	23.85	27.36	30.21	30.40	35.56	24.96	28.14	33.76	34.46	31.98	31.59	24.22	21.92	23.40	24.30	Revenues per sh	26.25
3.33	3.52	3.54	3.09	3.22	3.19	3.01	2.72	2.59	2.88	3.18	3.28	3.22	3.41	3.31	4.17	3.65	3.80	"Cash Flow" per sh	4.25
1.60	1.62	1.58	1.36	1.46	1.33	1.11	1.07	.91	1.21	1.44	1.67	1.62	1.64	1.50	2.29	1.60	1.70	Earnings per sh A	2.00
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	Div'd Decl'd per sh B ■	1.40
1.77	1.74	2.15	2.66	2.76	2.58	2.62	3.12	3.29	1.92	2.45	3.32	3.49	3.31	3.39	3.04	3.55	4.15	Cap'l Spending per sh	4.00
13.06	14.21	14.36	15.01	15.02	13.44	15.29	15.35	15.58	15.67	15.95	16.28	17.06	17.47	17.94	19.03	19.35	19.80	Book Value per sh C	22.00
71.20	73.62	75.84	80.69	80.98	81.46	83.43	90.52	92.52	94.69	96.04	97.93	101.26	102.57	107.46	108.58	109.00	109.00	Common Shs Outst'g D	112.00
11.8	13.5	13.8	19.2	18.3	20.3	21.6	23.2	19.8	18.6	17.1	15.8	16.2	15.9	20.4	13.6	Bold figures are		Avg Ann'l P/E Ratio	15.0
.60	.74	.79	1.01	.97	1.10	1.15	1.40	1.32	1.18	1.07	1.01	.91	.84	1.03	.71	Value Line		Relative P/E Ratio	.95
6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	6.9%	5.5%	5.0%	4.7%	4.7%	4.8%	4.1%	4.0%	estimates		Avg Ann'l Div'd Yield	4.7%
						2536.4	3218.9	2309.6	2665.0	3242.3	3375.0	3238.5	3239.5	2603.0	2380.7	2550	2650	Revenues ($mill)	2950
						93.6	92.2	84.9	115.4	140.1	164.9	163.4	170.2	161.8	250.1	180	190	Net Profit ($mill)	225
						35.4%	34.7%	34.1%	37.0%	35.1%	35.9%	34.0%	35.0%	36.5%	33.1%	36.5%	36.5%	Income Tax Rate	36.5%
						8.3%	14.2%	20.6%	7.4%	6.0%	6.9%	4.8%	5.5%	5.8%	4.6%	11.0%	11.0%	AFUDC % to Net Profit	9.0%
						47.6%	46.0%	48.0%	44.5%	44.9%	45.7%	44.0%	45.2%	43.5%	41.6%	44.0%	46.5%	Long-Term Debt Ratio	47.5%
						51.0%	52.7%	50.7%	54.3%	53.9%	53.1%	55.0%	53.8%	55.5%	57.5%	55.5%	52.5%	Common Equity Ratio	51.5%
						2501.8	2635.2	2840.8	2732.9	2841.3	3001.0	3142.9	3332.3	3473.5	3595.1	3810	4110	Total Capital ($mill)	4775
						2743.4	2907.4	3088.6	3165.9	3334.5	3594.8	3858.9	4148.8	4377.7	4603.5	4770	4990	Net Plant ($mill)	5525
						5.2%	4.7%	4.3%	5.6%	6.2%	6.7%	6.4%	6.2%	5.7%	7.9%	5.5%	5.5%	Return on Total Cap'l	6.0%
						7.1%	6.5%	5.8%	7.6%	8.9%	10.1%	9.3%	9.3%	8.2%	11.9%	8.5%	8.5%	Return on Shr. Equity	9.0%
						7.2%	6.5%	5.8%	7.7%	9.0%	10.2%	9.4%	9.4%	8.3%	12.0%	8.5%	8.5%	Return on Com Equity E	9.0%
						.8%	.5%	NMF	1.4%	2.1%	4.2%	3.7%	2.3%	1.5%	6.3%	2.0%	2.5%	Retained to Com Eq	3.0%
						89%	93%	116%	82%	78%	59%	61%	75%	83%	48%	77%	73%	All Div'ds to Net Prof F	70%

CAPITAL STRUCTURE as of 6/30/17
Total Debt $1668.4 mill. **Due in 5 Yrs** $493.6 mill.
LT Debt $1493.7 mill. **LT Interest** $70.3 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 6.0x)
Leases, Uncapitalized Annual rentals $12.0 mill.
Pension Assets-12/16 $1369.7 mill.
Oblig $1935.5 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100. Sinking fund ends 2018.
Common Stock 108,785,486 shs. **as of 7/27/17**
MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-1.0	-.2	-1.2
Avg. Indust. Use (MWH)	6118	5630	5350
Avg. Indust. Revs. per KWH (¢)	29.82	22.71	20.28
Capacity at Yearend (Mw)	2362	2224	2220
Peak Load, Winter (Mw)	1554	1610	1593
Annual Load Factor (%)	69.3	66.9	66.6
% Change Customers (yr-end)	+.8	+.5	+.5
Fixed Charge Cov. (%)	410	399	437

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-.5%	-2.0%	Nil
"Cash Flow"	1.5%	4.5%	2.5%
Earnings	2.5%	9.0%	1.5%
Dividends	- -	- -	2.0%
Book Value	2.5%	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	783.7	798.7	867.1	790.0	3239.5
2015	637.9	623.9	717.2	624.0	2603.0
2016	551.0	566.2	646.1	617.4	2380.7
2017	591.6	632.3	676.1	650	2550
2018	650	650	700	650	2650

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.45	.41	.46	.32	1.64
2015	.31	.33	.47	.39	1.50
2016	.30	.41	1.17	.41	2.29
2017	.31	.36	.52	.41	1.60
2018	.33	.41	.54	.42	1.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.31	.31	.31	.31	1.24
2014	.31	.31	.31	.31	1.24
2015	.31	.31	.31	.31	1.24
2016	.31	.31	.31	.31	1.24
2017	.31	.31	.31		

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company, Inc. (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 458,000 customers on O'ahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Electric. revenue breakdown: residential, 31%; commercial, 34%; large light & power, 34%; other, 1%. Generating sources: oil, 53%; purchased, 47%. Fuel costs: 43% of revs. '16 reported depr. rate (utility): 3.2%. Has 3,800 empls. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Internet: www.hei.com.

One of Hawaiian Electric Industries' utilities has received an interim rate increase. Hawaiian Electric Light Company (HELCO) was granted an interim hike of $9.9 million (3.4%), based on a return of 9.5% on a common-equity ratio of 56.7%. (The utility had filed for $19.3 million.) There is no time frame for a final order. Note that HELCO will file another rate case by the end of 2018.

The other two utilities have rate cases pending. Hawaiian Electric Company (HECO) is seeking an increase of $106.4 million (6.9%), based on a return of 10.6% on a common-equity of 57%. The utility is hoping for an interim decision by mid-December, but this might well slip into early 2018. Meanwhile, HECO will try to reach a settlement with the commission's staff and intervenors. Maui Electric Company (MECO) requested a boost of $30.1 million (9.3%), based on a return of 10.6% on a common-equity ratio of 56.9%. MECO expects an interim order in September.

The utilities need rate relief in order to reduce the shortfall in their earned returns on equity. For the 12-month period that ended on June 30th, HEI's utilities (as a group) earned an ROE of just 7.2%, well below their allowed ROEs (as shown in the footnotes). Regulatory mechanisms designed to reduce the effects of regulatory lag have not been as effective as the company had hoped.

Investors should not be alarmed by the steep earnings decline we expect in 2017. Last year, third-quarter profits were skewed by a $90 million (pretax) payment HEI received from NextEra Energy after the latter company's takeover bid was rejected by the state regulators. (Earnings would have been $1.75 a share in 2016 without the payment.) Our earnings estimate is within the company's targeted range of $1.55-$1.70 a share. We forecast improvement in 2018, thanks to rate relief and ongoing income growth at the American Savings Bank subsidiary.

We do not recommend this untimely stock. Its dividend yield is not much higher than the utility average, despite HEI's lack of dividend growth potential. With the recent price near the upper end of our 2020-2022 Target Price Range, total return potential is virtually zero.

Paul E. Debbas, CFA *October 27, 2017*

(A) Dil. EPS. Excl. gains (losses) from disc. ops.: '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (losses): '05, 11¢; '07, (9¢); '12, (25¢). Next earnings report due early Nov.
(B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail.
(C) Incl. intang. In '16: $9.57/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate allowed on com. eq. in '11: HECO, 10%; in '12: HELCO, 10%; in '13: MECO, 9%; earn. on avg. com. eq., '16: 12.4%. Regulat. Climate: Below Avg. (F) Excl. div'ds paid through reinv. plan.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	65

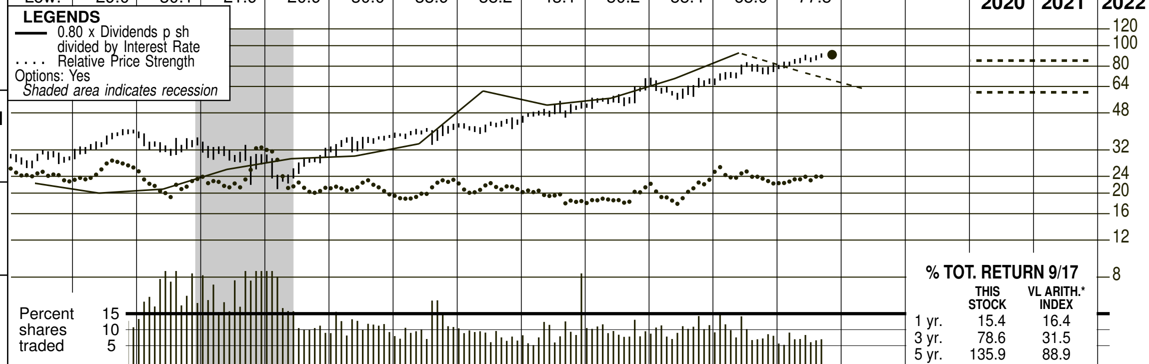
IDACORP, INC. NYSE-IDA

RECENT PRICE **90.59** | P/E RATIO **22.0** (Trailing: 22.9 / Median: 14.0) | RELATIVE P/E RATIO **1.09** | DIV'D YLD **2.6%** | **VALUE LINE**

TIMELINESS 4 Lowered 9/1/17
SAFETY 2 Raised 8/2/13
TECHNICAL 2 Raised 10/6/17
BETA .70 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5	83.4	92.0
Low:	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4	65.0	77.5

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range

2020	2021	2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(-5%)	*1%*
Low	60	(-35%)	*-6%*

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	8	10	0	0	0	0	0
to Sell	0	0	0	3	0	0	2	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	105	95	139
to Sell	110	125	91
Hld's(000)	38530	47507	45985

% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.4	16.4
3 yr.	78.6	31.5
5 yr.	135.9	88.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	*26.35*	*26.45*	Revenues per sh	*27.75*
5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	*7.45*	*7.70*	"Cash Flow" per sh	*8.75*
3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	*4.15*	*4.20*	Earnings per sh A	*4.75*
1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	*2.24*	*2.40*	Div'd Decl'd per sh B ■ †	*2.90*
4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	*6.50*	*6.55*	Cap'l Spending per sh	*6.75*
23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	*44.55*	*46.25*	Book Value per sh C	*51.75*
37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	*50.45*	*50.50*	Common Shs Outst'g D	*50.65*
11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	*Value Line*		Relative P/E Ratio	*.95*
4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $1745.9 mill. **Due in 5 Yrs** $230.6 mill.
LT Debt $1745.4 mill. **LT Interest** $81.1 mill.
(LT interest earned: 3.6x)

Pension Assets-12/16 $607.6 mill. **Oblig** $895.1 mill.

Pfd Stock None

Common Stock 50,393,584 shs. as of 7/28/17

MARKET CAP: $4.6 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	1270.3	1262.0	*1330*	*1335*	Revenues ($mill)	*1400*
82.3	98.4	124.4	142.5	166.9	168.9	182.4	193.5	194.7	198.3	*210*	*215*	Net Profit ($mill)	*240*
14.3%	16.3%	15.2%	- -	- -	13.4%	28.3%	8.0%	19.0%	15.5%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
9.7%	10.2%	10.5%	19.1%	23.3%	20.3%	12.3%	13.6%	16.3%	16.3%	*16.0%*	*16.0%*	AFUDC % to Net Profit	*15.0%*
48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	45.6%	44.8%	*43.5%*	*42.5%*	Long-Term Debt Ratio	*42.5%*
51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	54.4%	55.2%	*56.5%*	*57.5%*	Common Equity Ratio	*57.5%*
2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	3783.3	3898.5	*3990*	*4080*	Total Capital ($mill)	*4550*
2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	3992.4	4172.0	*4330*	*4490*	Net Plant ($mill)	*4925*
4.7%	5.3%	5.7%	6.0%	6.8%	6.5%	6.4%	6.6%	6.2%	6.1%	*6.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	*9.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	*9.5%*	*9.0%*	Return on Com Equity E	*9.0%*
2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	4.8%	4.3%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
64%	55%	46%	41%	36%	41%	43%	46%	50%	53%	*54%*	*57%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-3.6	+1.2	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.68	5.70	5.63
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3184	3402	3299
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.8	+1.8
Fixed Charge Cov. (%)	287	307	295

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	2.0%	3.5%	*1.5%*
"Cash Flow"	5.0%	4.5%	*4.5%*
Earnings	7.0%	5.5%	*3.5%*
Dividends	5.0%	10.0%	*7.0%*
Book Value	5.0%	5.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	292.7	317.8	382.2	289.8	1282.5
2015	279.4	336.3	369.2	285.4	1270.3
2016	281.0	315.4	372.0	293.6	1262.0
2017	302.5	333.0	*394.5*	*300*	*1330*
2018	*310*	*330*	*390*	*305*	*1335*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.55	.89	1.73	.69	3.85
2015	.47	1.31	1.46	.63	3.87
2016	.51	1.12	1.65	.66	3.94
2017	.66	.99	*1.93*	*.57*	*4.15*
2018	*.63*	*1.01*	*1.97*	*.59*	*4.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016	.51	.51	.51	.55	2.08
2017	.55	.55	.55	.59	

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 539,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 41%; commercial, 24%; industrial, 14%; irrigation, 12%; other, 9%. Generating sources: hydro, 39%; coal, 25%; gas, 10%; purchased, 26%. Fuel costs: 33% of revenues. '16 reported depreciation rate: 2.6%. Has 2,000 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

We have raised our 2017 earnings estimate for IDACORP by $0.10 a share, to $4.15. The company's utility subsidiary, Idaho Power, experienced summer weather that was hotter and drier than normal. (Dry weather helps the utility because it has a significant base of irrigation customers.) Idaho Power is also benefiting from strong customer growth. Over the 12-month period that ended on June 30th, the customer count rose 1.8%. Our revised estimate is above the company's targeted range of $3.95-$4.05, which is based on normal weather patterns.

The quality of earnings has improved, as well. This year, Idaho Power will not need a regulatory mechanism that is available to stabilize its earnings. The utility may book up to $25 million a year of accumulated deferred investment tax credits to augment its income if its earned return on equity falls below 9.5%. But thanks to its good performance in the first half of 2017, it will not have to record any of these credits.

We forecast just a slight profit increase in 2018. We assume a return to normal weather conditions. We are sticking with our earnings estimate of $4.20 a share.

The board of directors raised the dividend. The quarterly increase was $0.04 a share (7.3%), as we had estimated. IDACORP's goal is a payout ratio of 50%-60%. Management intends to recommend yearly increases of 5% or more until the upper end of the range is reached. The newly hiked dividend will be paid in late November.

Finances are sound. The fixed-charge coverage is healthy and the common-equity ratio is above average. Also, the company has no significant debt maturities until 2020. IDACORP merits a Financial Strength rating of A.

We advise investors to look elsewhere. The stock is ranked unfavorably for Timeliness. Moreover, it is priced expensively. The recent quotation is *above* our 2020-2022 Target Price Range. We think some takeover speculation is reflected in the stock price, as mid-cap utilities have been the targets of acquisitions in recent years. We advise against purchasing this equity in the hope of a buyout, however.

Paul E. Debbas, CFA *October 27, 2017*

(A) Diluted EPS. Excl. nonrecurring gains (loss): '03, 26¢; '05, (24¢); '06, 17¢. '14 earnings don't add due to rounding. Next earnings report due early Nov. **(B)** Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. intangibles. In '16: $28.15/sh. **(D)** In millions. **(E)** Rate base: Net original cost. Rate allowed on common equity in '11: 10% (imputed); earned on avg. com. eq., '16: 9.4%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	90

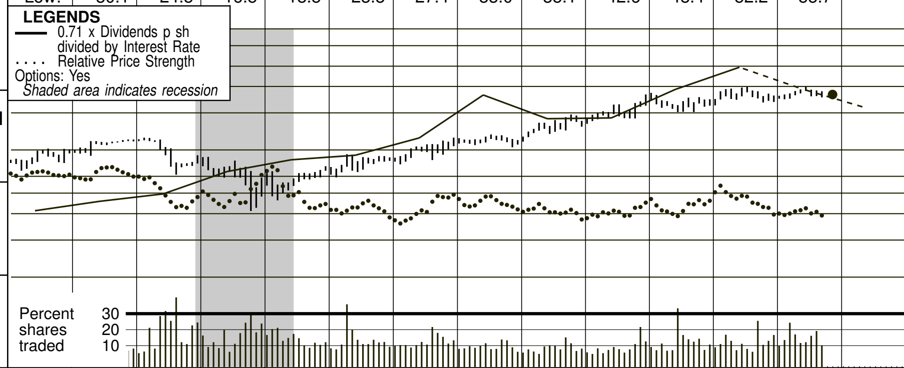
NORTHWESTERN NYSE-NWE

RECENT PRICE **58.63** | P/E RATIO **17.3** (Trailing: 17.0 Median: 16.0) | RELATIVE P/E RATIO **0.86** | DIV'D YLD **3.7%** | **VALUE LINE**

TIMELINESS 3 Lowered 8/4/17
SAFETY 3 New 5/4/12
TECHNICAL 2 Lowered 10/27/17
BETA .70 (1.00 = Market)

High:	35.8	36.7	29.7	26.8	30.6	36.6	38.0	47.2	58.7	59.7	63.8	63.9	
Low:	30.1	24.5	16.5	18.5	23.8	27.4	33.0	35.1	42.6	48.4	52.2	55.7	

LEGENDS
—— 0.71 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range

2020	2021	2022

120 / 100 / 80 / 64 / 48 / 32 / 24 / 20 / 16 / 12 / 8

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+30%)	*10%*
Low	50	(-15%)	*Nil*

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	4	5	9	0	4	1	0	1
to Sell	0	0	0	4	0	2	0	0	1

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	135	142	124
to Sell	94	96	101
Hld's(000)	47832	55386	56186

% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.5	16.4
3 yr.	39.5	31.5
5 yr.	87.9	88.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
- -	- -	- -	29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	***26.80***	***27.95***	**Revenues per sh**	***32.00***
- -	- -	- -	3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	***6.90***	***7.15***	**"Cash Flow" per sh**	***8.25***
- -	- -	- -	d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	***3.40***	***3.50***	**Earnings per sh A**	***4.00***
- -	- -	- -	- -	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	***2.10***	***2.20***	**Div'd Decl'd per sh B ■ †**	***2.50***
- -	- -	- -	2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	***6.15***	***6.60***	**Cap'l Spending per sh**	***6.75***
- -	- -	- -	19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	***35.85***	***37.05***	**Book Value per sh C**	***41.00***
- -	- -	- -	35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	***48.50***	***48.65***	**Common Shs Outst'g D**	***49.10***
- -	- -	- -	- -	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	***Bold figures are***		**Avg Ann'l P/E Ratio**	***15.0***
- -	- -	- -	- -	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	***Value Line***		**Relative P/E Ratio**	***.95***
- -	- -	- -	- -	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	***estimates***		**Avg Ann'l Div'd Yield**	***4.1%***

CAPITAL STRUCTURE as of 6/30/17
Total Debt $2122.8 mill. **Due in 5 Yrs** $565.3 mill.
LT Debt $1817.1 mill. **LT Interest** $83.6 mill.
Incl. $23.3 mill. capitalized leases.
(LT interest earned: 3.0x)

Pension Assets-12/16 $524.6 mill. **Oblig** $646.0 mill.

Pfd Stock None

Common Stock 48,471,447 shs.
as of 7/21/17
MARKET CAP: $2.8 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
1200.1	1260.8	1141.9	1110.7	1117.3	1070.3	1154.5	1204.9	1214.3	1257.2	***1300***	***1360***	**Revenues ($mill)**	***1575***
53.2	67.6	73.4	77.4	92.6	83.7	94.0	120.7	138.4	164.2	***165***	***170***	**Net Profit ($mill)**	***200***
37.8%	37.3%	17.2%	25.0%	9.8%	9.6%	13.2%	- -	13.7%	13.7%	***8.5%***	***12.0%***	**Income Tax Rate**	***20.0%***
2.5%	2.3%	4.4%	14.2%	3.3%	9.4%	8.7%	8.9%	9.8%	4.3%	***6.0%***	***6.0%***	**AFUDC % to Net Profit**	***5.0%***
50.1%	46.8%	56.4%	57.2%	52.2%	53.8%	53.5%	53.4%	53.1%	52.0%	***51.0%***	***47.0%***	**Long-Term Debt Ratio**	***48.0%***
49.9%	53.2%	43.6%	42.8%	47.8%	46.2%	46.5%	46.6%	46.9%	48.0%	***49.0%***	***53.0%***	**Common Equity Ratio**	***52.0%***
1648.4	1434.3	1803.9	1916.4	1797.1	2020.7	2215.7	3168.0	3408.6	3493.9	***3530***	***3400***	**Total Capital ($mill)**	***3850***
1770.9	1839.7	1964.1	2118.0	2213.3	2435.6	2690.1	3758.0	4059.5	4214.9	***4345***	***4485***	**Net Plant ($mill)**	***4875***
5.0%	7.0%	6.0%	5.9%	7.0%	5.5%	5.5%	4.8%	5.2%	5.9%	***6.0%***	***6.0%***	**Return on Total Cap'l**	***6.0%***
6.5%	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	***9.5%***	***9.5%***	**Return on Shr. Equity**	***10.0%***
6.5%	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	***9.5%***	***9.5%***	**Return on Com Equity E**	***10.0%***
.7%	2.3%	3.2%	3.5%	4.7%	3.2%	3.5%	3.8%	3.0%	4.1%	***3.5%***	***3.5%***	**Retained to Com Eq**	***4.0%***
89%	74%	66%	63%	56%	65%	61%	54%	65%	58%	***62%***	***63%***	**All Div'ds to Net Prof**	***62%***

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+.7	-.1	-.7
Avg. Indust. Use (MWH)	28987	30133	29784
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2044	2096	2138
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.3	+1.2
Fixed Charge Cov. (%)	217	252	253

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '14-'16 to '20-'22**
Revenues	-2.0%	-4.0%	*4.0%*
"Cash Flow"	5.5%	4.0%	*5.5%*
Earnings	- -	7.0%	*4.5%*
Dividends	9.5%	6.0%	*5.0%*
Book Value	5.0%	8.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	369.7	270.3	251.9	313.0	1204.9
2015	346.0	270.6	272.7	325.0	1214.3
2016	332.5	293.1	301.0	330.6	1257.2
2017	367.3	283.9	***310***	***338.8***	***1300***
2018	***375***	***310***	***325***	***350***	***1360***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.17	.20	.77	.85	2.99
2015	1.09	.38	.51	.93	2.90
2016	.82	.73	.92	.92	3.39
2017	1.17	.44	***.76***	***1.03***	***3.40***
2018	***1.15***	***.45***	***.80***	***1.10***	***3.50***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.38	.38	.38	.38	1.52
2014	.40	.40	.40	.40	1.60
2015	.48	.48	.48	.48	1.92
2016	.50	.50	.50	.50	2.00
2017	.525	.525	.525		

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 427,000 electric customers in Montana and South Dakota and 283,000 gas customers in Montana (87% of gross margin), South Dakota (12%), and Nebraska (1%). Electric revenue breakdown: residential, 40%; commercial, 51%; industrial, 5%; other, 4%. Generating sources: hydro, 34%; coal, 30%; other, 10%; purchased, 26%. Fuel costs: 32% of revenues. '16 reported deprec. rate: 3.0%. Has 1,600 employees. Chairman: Dr. E. Linn Draper Jr. President & CEO: Robert C. Rowe. Incorporated: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern received a gas rate increase in Montana. The Montana Public Service Commission (MPSC) raised rates by $5.1 million, based on a 9.55% return on a 46.8% common-equity ratio. This was less than the $5.7 million the company had reached in a settlement with the MPSC's staff and some intervenors, and well below the $9.4 million the utility had sought in rebuttal testimony. The allowed ROE is a reduction from the previous 9.8%. New tariffs took effect at the start of September.

There is a regulatory uncertainty in Montana. The MPSC changed the fuel-adjustment clause, which raises the risk of a disallowance of power costs for NorthWestern in the state. Note that the utility expects to file an electric rate case in the state in 2018.

We have trimmed our 2017 and 2018 share-earnings estimates by a nickel. This reflects June-quarter results that were below our estimate. Our revised forecast is at the midpoint of NorthWestern's targeted range of $3.30-$3.50. Earnings growth in the near term is likely to be in the low single-digit range.

The company is awaiting resolution of two legal matters. NorthWestern appealed an unfavorable ruling from the Federal Energy Regulatory Commission to the U.S. Circuit Court of Appeals. The regulators had ruled that only 4% of the cost of a new gas-fired plant may be allocated to its (federally regulated) wholesale business, instead of the 20% the utility requested. This forced the company to take a $0.12-a-share charge in 2012. A ruling might come as early as the current quarter. NorthWestern also appealed an unfavorable MPSC ruling to the state courts. Its disallowance of certain costs hurt the bottom line by $0.13 a share in the first quarter of 2016 (*included* in our earnings presentation). A decision is likely by July.

This stock's dividend yield is slightly above the utility average. Total return potential to 2020-2022 is unimpressive, but still a bit higher than the industry mean. As is true for most utility equities, the recent quotation of NorthWestern stock is within our 3- to 5-year Target Price Range.

Paul E. Debbas, CFA *October 27, 2017*

(A) Diluted EPS. Excl. gain (loss) on disc. ops.: '05, (6¢); '06, 1¢; nonrec. gains: '12, 39¢ net; '15, 27¢. '15 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '16: $19.87/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '16: 10.1%. Regul. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	85

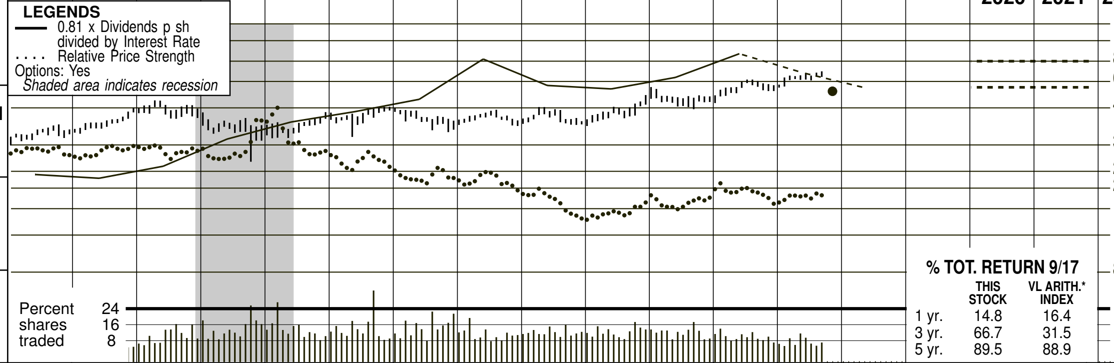
PG&E CORP. NYSE-PCG

RECENT PRICE 57.44 | P/E RATIO 15.9 (Trailing: 14.2 Median: 17.0) | RELATIVE P/E RATIO 0.79 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Lowered 8/25/17
SAFETY 2 Raised 7/28/17
TECHNICAL 2 Lowered 10/20/17
BETA .65 (1.00 = Market)

High:	48.2	52.2	45.7	45.8	48.6	48.0	47.0	48.5	55.2	60.2	65.4	71.6
Low:	36.3	42.6	26.7	34.5	34.9	36.8	39.4	39.9	39.4	47.3	50.7	49.8

LEGENDS
— 0.81 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+40%)	12%
Low	60	(+5%)	6%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	9	0	14	7	0	0
to Sell	0	0	0	0	0	0	0	0	3

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	290	288	297
to Sell	237	233	237
Hld's(000)	415770	455198	450461

Percent shares traded 24 / 16 / 8

% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.8	16.4
3 yr.	66.7	31.5
5 yr.	89.5	88.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	36.28	34.92	34.16	35.91	34.21	34.85	*35.35*	*36.35*	Revenues per sh	*41.00*
5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	8.08	7.32	6.33	8.13	7.29	8.23	*9.20*	*9.65*	"Cash Flow" per sh	*10.75*
3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	2.78	2.07	1.83	3.06	2.00	2.83	*3.65*	*3.90*	Earnings per sh A	*4.50*
- -	- -	- -	- -	1.23	1.32	1.44	1.56	1.68	1.82	1.82	1.82	1.82	1.82	1.82	1.93	*2.08*	*2.27*	Div'd Decl'd per sh B ■ †	*2.90*
7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	9.79	10.74	11.40	10.16	10.51	11.26	*11.45*	*11.75*	Cap'l Spending per sh	*11.50*
11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	29.35	30.35	31.41	33.09	33.69	35.39	*37.30*	*39.30*	Book Value per sh C	*45.00*
363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	412.26	430.72	456.67	475.91	492.03	506.89	*515.00*	*520.00*	Common Shs Outst'g D	*535.00*
4.8	- -	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	15.5	20.7	23.7	15.0	26.4	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.25	- -	.54	.73	.82	.80	.89	.73	.87	1.01	.97	1.32	1.33	.79	1.33	1.10	*Value Line*		Relative P/E Ratio	*.95*
- -	- -	- -	- -	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	4.2%	4.2%	4.2%	4.0%	3.4%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
13237	14628	13399	13841	14956	15040	15598	17090	16833	17666	*18200*	*18900*	Revenues ($mill)	*21900*
1020.0	1198.0	1168.0	1113.0	1132.0	893.0	828.0	1450.0	988.0	1431.0	*1890*	*2065*	Net Profit ($mill)	*2445*
34.6%	26.2%	31.1%	33.0%	30.3%	23.9%	24.5%	19.2%	19.2%	3.7%	*18.0%*	*20.0%*	Income Tax Rate	*20.0%*
9.4%	9.5%	11.9%	14.4%	11.2%	17.5%	17.9%	10.0%	15.7%	11.4%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
52.6%	52.2%	51.4%	49.6%	48.8%	48.7%	46.6%	48.5%	48.8%	47.1%	*46.5%*	*45.5%*	Long-Term Debt Ratio	*47.0%*
46.1%	46.5%	47.4%	49.3%	50.2%	50.4%	52.5%	50.7%	50.4%	52.1%	*53.0%*	*54.0%*	Common Equity Ratio	*52.5%*
18558	20163	21793	22863	24119	25956	27311	31050	32858	34412	*36375*	*38000*	Total Capital ($mill)	*46200*
23656	26261	28892	31449	33655	37523	41252	43941	46723	50581	*53625*	*56725*	Net Plant ($mill)	*65300*
7.4%	7.8%	6.7%	6.2%	5.9%	4.7%	4.2%	5.8%	4.1%	5.2%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
11.6%	12.4%	11.0%	9.6%	9.2%	6.7%	5.7%	9.1%	5.9%	7.9%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.0%*
11.8%	12.6%	11.2%	9.7%	9.2%	6.7%	5.7%	9.1%	5.9%	7.9%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
6.0%	6.8%	5.5%	3.9%	3.4%	1.0%	.2%	3.9%	.7%	2.8%	*4.0%*	*4.5%*	Retained to Com Eq	*3.5%*
50%	47%	52%	61%	63%	85%	96%	58%	88%	65%	*57%*	*58%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $18496 mill. **Due in 5 Yrs** $5143 mill.
LT Debt $16616 mill. **LT Interest** $764 mill.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $44 mill.
Pension Assets-12/16 $14729 mill. **Oblig** $17305 mill.
Pfd Stock $252 mill. **Pfd Div'd** $14 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par.
Common Stock 512,821,658 shs. **as of 7/21/17**
MARKET CAP: $29 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-.2	-.5	-3.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.98	9.73	9.90
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.6	+.7	+.7
Fixed Charge Cov. (%)	304	189	242

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	1.0%	-.5%	*2.5%*
"Cash Flow"	1.5%	-1.0%	*5.5%*
Earnings	1.0%	-2.0%	*9.5%*
Dividends	8.0%	1.0%	*7.5%*
Book Value	5.0%	3.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3891	3952	4939	4308	17090
2015	3899	4217	4550	4167	16833
2016	3974	4169	4810	4713	17666
2017	4268	4250	*4900*	*4782*	*18200*
2018	*4400*	*4400*	*5150*	*4950*	*18900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.49	.57	1.71	.27	3.06
2015	.27	.83	.63	.27	2.00
2016	.22	.46	.77	1.36	2.83
2017	1.13	.79	*1.03*	*.70*	*3.65*
2018	*1.10*	*.90*	*1.15*	*.75*	*3.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.455	.455	.455	.455	1.82
2014	.455	.455	.455	.455	1.82
2015	.455	.455	.455	.455	1.82
2016	.455	.455	.49	.49	1.89
2017	.49	.49	.53	.53	

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California (population 16 million). Has 5.4 million electric and 4.5 million gas customers. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 11%; agricultural, 9%; other, 1%. Generating sources: nuclear, 24%; hydro, 11%; gas, 7%; purchased, 58%. Fuel costs: 30% of revenues. '16 reported depreciation rate (utility): 3.8%. Has 24,000 employees. Chairman: Anthony F. Earley, Jr. President & CEO: Geisha J. Williams. Incorporated: California. Address: 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. Telephone: 415-973-1000. Internet: www.pgecorp.com.

The price of PG&E stock has fallen lately due to concerns that power lines of its utility subsidiary caused or contributed to wildfires in northern California. Liability has not been established, but if the company's lines had anything to do with the fires, the company has about $800 million in liability insurance. In 2015, a fire led to third-party claims of an estimated $750 million, and PG&E also incurred cleanup and legal costs. These expenses (net of insurance recoveries) reduced earnings by $0.27 a share in 2016. The insurance recoveries boosted profits by $0.03 a share in the first half of 2017.

Our 2017 and 2018 earnings estimates do not reflect any possible costs stemming from the latest wildfires. We have been expecting significant earnings growth in 2017, followed by a further increase in 2018, as costs associated with a pipeline explosion in San Bruno, California in 2010 diminish. We figure these expenses will be gone in 2018 after being substantially lower this year. The utility is also benefiting from rate increases totaling $88 million in 2017, $444 million in 2018, and $361 million in 2019.

PG&E is awaiting a ruling from the California Public Utilities Commission (CPUC) on a settlement regarding the Diablo Canyon nuclear station. The plant was facing political and environmental opposition, so the company agreed to shut the two units upon expiration of their operating licenses in 2024 and 2025. This forced PG&E to take a $0.06-a-share charge (*included* in our earnings presentation) in the second quarter, due to a disallowance of certain costs, such as those of license renewal. Before the settlement, the utility was preparing to apply for 20-year license extensions for each unit. The CPUC's ruling is expected by yearend.

Due to the uncertainty surrounding the latest wildfires, we advise most investors to look elsewhere. Even after the decline in the price of PG&E stock, which is 20% off its 52-week high, this equity still isn't cheap. Intrepid investors might well be rewarded if the market's fears prove to be overblown, but most utility accounts are better off not taking such a chance, in our view.

Paul E. Debbas, CFA *October 27, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '04, $6.95; '09, 18¢; '11, (68¢); '12, (15¢); '15, (21¢); '16, (5¢); gain from disc. ops.: '08, 41¢. '14 & '16 EPS don't sum due to change in shs. outstanding. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '16: $15.69/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.4%; earned on avg. com. eq., '16: 8.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	45

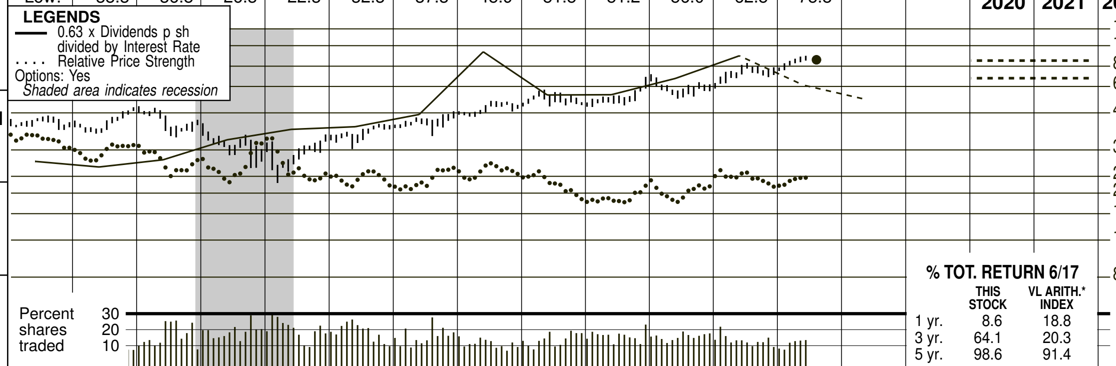
PINNACLE WEST NYSE-PNW

RECENT PRICE 85.76 | P/E RATIO 20.2 (Trailing: 20.9 Median: 15.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 2 Lowered 7/28/17
SAFETY 1 Raised 5/3/13
TECHNICAL 2 Lowered 7/28/17
BETA .65 (1.00 = Market)

High:	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3	82.8	89.6	
Low:	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0	62.5	75.8	

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(Nil)	3%
Low	70	(-20%)	-1%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	12	2	0	0	12	1	0	5
to Sell	1	0	0	3	0	0	4	0	6

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	182	198	229
to Sell	192	211	191
Hld's(000)	90564	92991	105747

% TOT. RETURN 6/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.6	18.8
3 yr.	64.1	20.3
5 yr.	98.6	91.4

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	*32.60*	*34.65*	Revenues per sh	*39.50*
8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	*9.90*	*10.35*	"Cash Flow" per sh	*12.00*
3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	*4.25*	*4.45*	Earnings per sh A	*5.25*
1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	*2.68*	*2.81*	Div'd Decl'd per sh B ■	*3.25*
12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	*12.55*	*10.50*	Cap'l Spending per sh	*10.00*
29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	*44.60*	*46.25*	Book Value per sh C	*51.75*
84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	*112.00*	*112.50*	Common Shs Outst'g D	*114.00*
12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	*Value Line*		Relative P/E Ratio	*.90*
3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
						3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	3498.7	*3650*	*3900*	Revenues ($mill)	*4500*
						298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	437.3	442.0	*475*	*505*	Net Profit ($mill)	*600*
						33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	33.9%	*33.5%*	*33.5%*	Income Tax Rate	*33.5%*
						14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	14.1%	*15.0%*	*11.0%*	AFUDC % to Net Profit	*7.0%*
						47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	45.6%	*48.5%*	*46.0%*	Long-Term Debt Ratio	*46.0%*
						53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	54.4%	*51.5%*	*54.0%*	Common Equity Ratio	*54.0%*
						6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	8825.4	*9720*	*9625*	Total Capital ($mill)	*10925*
						8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	11809	12714	*13500*	*14000*	Net Plant ($mill)	*15100*
						5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	6.0%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
						8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
						8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	*9.5%*	*9.5%*	Return on Com Equity E	*10.0%*
						2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
						70%	96%	89%	66%	68%	58%	58%	62%	59%	62%	*63%*	*63%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 3/31/17
Total Debt $4606.2 mill. **Due in 5 Yrs** $1264.3 mill.
LT Debt $4273.9 mill. **LT Interest** $198.0 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $12.3 mill.
Pension Assets-12/16 $2675.4 mill. **Oblig** $3204.5 mill.
Pfd Stock None

Common Stock 111,560,427 shs. as of 4/25/17
MARKET CAP: $9.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-1.8	+1.3	+.3
Avg. Indust. Use (MWH)	659	658	640
Avg. Indust. Revs. per KWH (¢)	8.26	8.17	8.37
Capacity at Peak (Mw)	9259	9250	9192
Peak Load, Summer (Mw)	7007	7031	7051
Annual Load Factor (%)	48.6	48.3	48.0
% Change Customers (yr-end)	+1.2	+1.3	+1.3
Fixed Charge Cov. (%)	404	438	416

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	- -	.5%	4.0%
"Cash Flow"	1.5%	3.5%	5.0%
Earnings	3.5%	6.5%	5.5%
Dividends	2.5%	3.0%	5.0%
Book Value	2.0%	4.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	890.7	1199.1	734.4	3495.4
2016	677.2	915.4	1166.9	739.2	3498.7
2017	677.7	*950*	*1247.3*	*775*	*3650*
2018	*750*	*1000*	*1325*	*825*	*3900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.14	1.19	2.20	.05	3.58
2015	.14	1.10	2.30	.37	3.92
2016	.04	1.08	2.35	.47	3.95
2017	.21	*1.24*	*2.40*	*.40*	*4.25*
2018	*.20*	*1.25*	*2.60*	*.40*	*4.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.545	.545	.545	.5675	2.20
2014	.5675	.5675	.5675	.595	2.30
2015	.595	.595	.595	.625	2.41
2016	.625	.625	.625	.655	2.53
2017	.655	.655			

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.2 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 50%; commercial, 40; industrial, 5%; other, 5%. Generating sources: nuclear, 28%; gas & other, 26%; coal, 20%; purchased, 26%. Fuel costs: 31% of revenues. '16 reported deprec. rate: 2.7%. Has 6,300 employees. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary is still awaiting an order on its regulatory settlement. Arizona Public Service (APS) filed for a rate increase of $165.9 million (5.7%), based on a 10.5% return on a 55.8% common-equity ratio. The utility also asked for changes in rate design so that solar customers would not be subsidized by nonsolar users to the extent they are today. APS, the commission's staff, and intervenors reached a settlement that (if approved by the commission) will raise rates by $94.6 million (3.3%), based on a 10% return on a 55.8% common-equity ratio. The solar subsidization problem would be reduced initially, with less subsidization each subsequent year. Finally, there would be a rate moratorium through mid-2019. An administrative law judge will put forth a recommendation before the commission issues its order. The company had hoped that new tariffs would go into effect on July 1st, but this will happen whenever the regulators decide they will take effect.

We have trimmed our 2017 earnings estimate by $0.05 a share. We had based our estimate on a midyear rate hike, but the delay will affect the company's income. (Management is not providing earnings guidance while the rate case is pending.) We are sticking with our profit forecast for 2018, as next year will have a full year's effect of the rate decision.

Two significant projects are under construction. The utility is adding pollution control equipment to two units of a coal-fired plant. The $400 million project is expected to be completed in the spring of 2018. APS is building five gas-fired units to replace old facilities and increase generating capacity by 220 megawatts. The $500 million project is scheduled for completion by the spring of 2019. Costs associated with these projects will be deferred for recovery in a future rate case, if the aforementioned regulatory settlement is approved.

This timely stock is ranked 1 (Highest) for Safety. However, the dividend yield does not stand out among utility stocks, and with the recent price above the upper end of our 2020-2022 Target Price Range, total return potential is uninspiring.

Paul E. Debbas, CFA *July 28, 2017*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically pd. in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. In '16: $14.54/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '16: 9.4%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

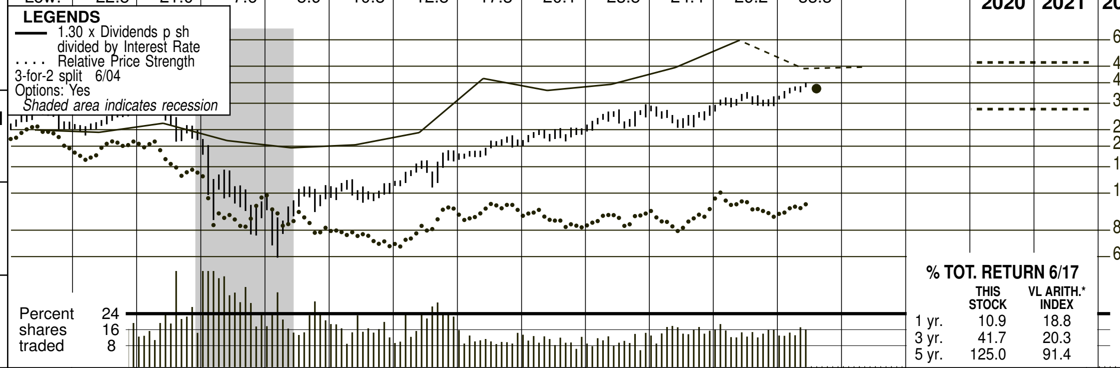
PNM RESOURCES NYSE-PNM

RECENT PRICE	37.55	P/E RATIO	20.3 (Trailing: 20.9 / Median: 17.0)	RELATIVE P/E RATIO	1.03	DIV'D YLD	2.6%	VALUE LINE

TIMELINESS 1 Raised 5/5/17
SAFETY 3 Lowered 5/9/08
TECHNICAL 2 Raised 7/21/17
BETA .75 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2	36.2	40.1
Low:	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4	29.2	33.3

Target Price Range
2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+35%)	*10%*
Low	30	(-20%)	*-2%*

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	6	0	8
to Sell	0	0	0	0	0	0	2	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	98	127	108
to Sell	129	108	111
Hld's(000)	75779	77690	84373

% TOT. RETURN 6/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.9	18.8
3 yr.	41.7	20.3
5 yr.	125.0	91.4

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	*18.15*	*18.75*	Revenues per sh	*20.30*
4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.62	3.98	4.28	*4.50*	*4.65*	"Cash Flow" per sh	*4.70*
2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.64	1.65	*1.85*	*1.80*	Earnings per sh A	*2.50*
.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.80	.88	*.97*	*1.07*	Div'd Decl'd per sh B ■†	*1.37*
4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	*5.65*	*5.50*	Cap'l Spending per sh	*5.50*
17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	*23.60*	*24.50*	Book Value per sh C	*25.50*
58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	*80.00*	*80.00*	Common Shs Outst'g D	*80.00*
7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	16.8	19.8	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.85	1.04	*Value Line*		Relative P/E Ratio	*1.00*
2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	2.9%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 3/31/17
Total Debt $2687.3 mill. **Due in 5 Yrs** $1602 mill.
LT Debt $1969.3 mill. **LT Interest** $110 mill.
(LT interest earned: 2.4x)
Pension Assets-12/16 $604.2 mill.
Oblig. $688.8 mill.

Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 4/24/17
MARKET CAP: $3.0 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	1363.0	*1450*	*1500*	Revenues ($mill)	*1625*
59.9	8.1	53.5	80.0	96.6	105.6	113.5	116.3	131.5	132.4	*150*	*145*	Net Profit ($mill)	*190*
5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	34.5%	33.9%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
--	--	6.4%	7.1%	8.8%	7.2%	1.3%	--	1.3%	1.5%	*2.0%*	*3.0%*	AFUDC % to Net Profit	*8.0%*
42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	54.1%	55.7%	*53.5%*	*53.0%*	Long-Term Debt Ratio	*52.5%*
57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	*45.5%*	*46.0%*	Common Equity Ratio	*46.5%*
2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	3633.3	3806.8	*4025*	*4150*	Total Capital ($mill)	*4385*
2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4535.4	4904.7	*4900*	*5050*	Net Plant ($mill)	*5270*
3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	5.1%	5.2%	5.2%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.9%	7.8%	*8.0%*	*8.0%*	Return on Shr. Equity	*9.5%*
3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.9%	7.9%	*8.0%*	*8.0%*	Return on Com Equity E	*9.5%*
NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.2%	4.1%	3.7%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
117%	NMF	86%	58%	47%	43%	45%	51%	49%	54%	*52%*	*53%*	All Div'ds to Net Prof	*56%*

ELECTRIC OPERATING STATISTICS F

	2014	2015	2016
% Change Retail Sales (KWH)	-2.9	-2.1	+2.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2572	2707	2787
Peak Load, Summer (Mw)	2008	1948	1889
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.7	+.6	+.9
Fixed Charge Cov. (%)	241	250	N/A

BUSINESS: PNM Resources is a holding company with two regulated electric utilities. Its Public Service of New Mexico unit (PNM) provides power generation, tranmission, and distribution services across north central New Mexico, including the cities of Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power throughout New Mexico. Electric rev. breakdown '16: residential, 29%; commercial, 31%; industrial, 18%; other, 22%. Fuels: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 49% of revenues. '16 depreciation rate: 3.3%. Has 1,881 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-5.0%	-2.5%	*1.5%*
"Cash Flow"	1.5%	8.0%	*5.0%*
Earnings	--	13.5%	*9.0%*
Dividends	0.5%	10.0%	*10.0%*
Book Value	1.0%	2.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	352.9	417.4	335.9	1439.1
2016	311.0	315.4	400.4	336.2	1363.0
2017	330.2	*335*	*425*	*359.8*	*1450*
2018	*340*	*345*	*440*	*375*	*1500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.16	.36	.69	.24	1.45
2015	.21	.44	.76	.23	1.64
2016	.13	.40	.78	.34	1.65
2017	.28	*.42*	*.79*	*.36*	*1.85*
2018	*.27*	*.41*	*.77*	*.35*	*1.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22	.22	.22	.22	.88
2017	.2425	.2425			

PNM Resources has filed a proposed settlement agreement in a general rate case. Indeed, in early May, the holding company's regulated power unit (Public Service of New Mexico) submitted a revised plan to increase retail electricity rates that apparently has the backing of key constituencies, including Wal-Mart and the Sierra Club. Notably, it is our understanding that the rate hike will now likely be phased in over a two-year period (+3,9% in 2018; +3.4% in 2019), rather than all at once, and that the slower implementation will make 2018 something of a transitional year. With that in mind, we have lowered our share-net call for next year by $0.20, to $1.80.

We still look for earnings to reach $2.50 a share within the next three to five years. Key to achieving that goal will be the utility's ability to both earn authorized returns on its regulated businesses and minimize regulatory lag. A better regional economy should help, as well. On that front, certain leading indicators of residential and commercial growth recently turned positive. What's more, Facebook's recent decision to build a data center in Los Lunas (south of Albuquerque) may spur other companies to consider the Land of Enchantment for major projects.

PNM will next review its dividend policy sometime in December. At that meeting, we expect the board of directors to raise the quarterly distribution by roughly 10%, to 26.7 cents a share. What's more, it appears that PNM remains committed to increasing the dividend at a rate that's slightly above targeted earnings growth of 8% or so, as it looks to potentially reach a payout ratio that is closer to 60%.

Shares of PNM Resources are now ranked 1 (Highest) for relative year-ahead price performance, having moved up a notch on our Timeliness scale since late April. At the stock's recent quotation, however, long-term total return potential is unremarkable. At 2.6%, the dividend yield is nearly 70 basis points below that of the leading utility ETF (the XLU). What's more, the issue is already trading within our 3- to 5-year Target Price Range.

Nils C. Van Liew *July 28, 2017*

(A) EPS dil. Excl. n/r gains (losses): '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13, (16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due early Aug. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '15: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Below Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	75

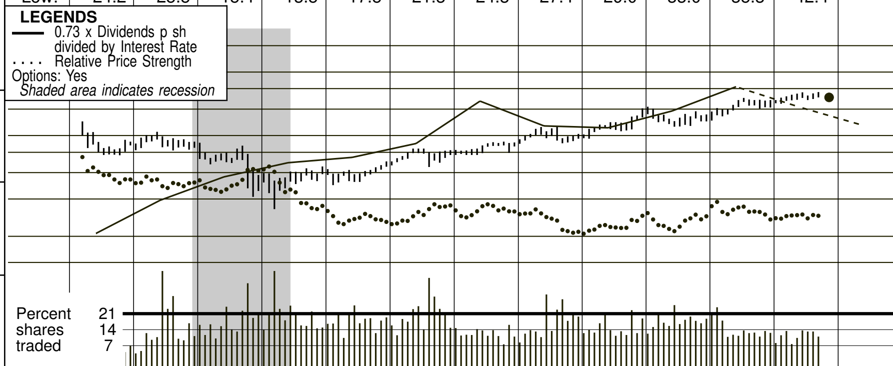
PORTLAND GENERAL NYSE-POR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
45.50	20.1	(Trailing: 20.3 Median: 15.0)	1.00	3.1%	VALUE LINE

TIMELINESS 3 Raised 9/29/17
SAFETY 2 Raised 5/4/12
TECHNICAL 2 Raised 10/6/17
BETA .70 (1.00 = Market)

High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0	45.2	48.2
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0	35.3	42.4

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(Nil)	3%
Low	35	(-25%)	-2%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	7	0	0	0	10	0	0
to Sell	0	0	0	1	0	2	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	136	140	147
to Sell	116	126	112
Hld's(000)	84377	90689	88988

% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.3	16.4
3 yr.	55.8	31.5
5 yr.	97.1	88.9

2001	2002	2003	2004	2005F	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
- -	- -	- -	- -	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	*22.40*	*23.20*	Revenues per sh	*25.50*
- -	- -	- -	- -	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	*6.10*	*6.50*	"Cash Flow" per sh	*7.75*
- -	- -	- -	- -	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	*2.25*	*2.35*	Earnings per sh A	*3.00*
- -	- -	- -	- -	- -	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	*1.34*	*1.42*	Div'd Decl'd per sh B ■ †	*1.70*
- -	- -	- -	- -	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	*6.35*	*5.20*	Cap'l Spending per sh	*3.25*
- -	- -	- -	- -	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	*27.20*	*28.05*	Book Value per sh C	*31.25*
- -	- -	- -	- -	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	*89.20*	*89.40*	Common Shs Outst'g D	*90.00*
- -	- -	- -	- -	- -	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
- -	- -	- -	- -	- -	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	*Value Line*		Relative P/E Ratio	*.85*
- -	- -	- -	- -	- -	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $2350 mill. **Due in 5 Yrs** $610 mill.
LT Debt $2200 mill. **LT Interest** $106 mill.
Incl. $51 mill. capitalized leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $10 mill.
Pension Assets-12/16 $559 mill.
Oblig $797 mill.
Pfd Stock None

Common Stock 89,062,560 shs.
as of 7/17/17

MARKET CAP: $4.1 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	1898.0	1923.0	*2000*	*2075*	Revenues ($mill)	*2300*
145.0	87.0	95.0	125.0	147.0	141.0	137.0	175.0	172.0	193.0	*200*	*210*	Net Profit ($mill)	*270*
33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	20.7%	20.6%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	19.8%	16.6%	*7.0%*	*5.0%*	AFUDC % to Net Profit	*2.0%*
49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	47.8%	48.4%	*51.5%*	*49.0%*	Long-Term Debt Ratio	*50.5%*
50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	52.2%	51.6%	*48.5%*	*51.0%*	Common Equity Ratio	*49.5%*
2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	4329.0	4544.0	*5000*	*4935*	Total Capital ($mill)	*5675*
3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	6012.0	6434.0	*6690*	*6775*	Net Plant ($mill)	*6450*
6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	5.4%	5.6%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.5%*
11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	*8.5%*	*8.5%*	Return on Com Equity E	*9.5%*
6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	3.3%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
40%	69%	76%	62%	54%	57%	61%	50%	56%	57%	*59%*	*60%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-.8	+.6	-2.1
Avg. Indust. Use (MWH)	16577	17485	16146
Avg. Indust. Revs. per KWH (¢)	5.13	5.01	4.99
Capacity at Peak (Mw)	4910	4609	4730
Peak Load, Winter (Mw) G	3866	3914	3726
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+1.2	+1.2
Fixed Charge Cov. (%)	248	243	271

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-.5%	-1.5%	*2.0%*
"Cash Flow"	2.0%	4.5%	*5.0%*
Earnings	7.0%	5.5%	*6.0%*
Dividends	13.5%	3.0%	*6.0%*
Book Value	3.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	493	423	484	500	1900
2015	473	450	476	499	1898
2016	487	428	484	524	1923
2017	530	449	*495*	*526*	*2000*
2018	*545*	*460*	*525*	*545*	*2075*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.73	.43	.47	.55	2.18
2015	.62	.44	.40	.57	2.04
2016	.68	.42	.38	.68	2.16
2017	.82	.36	*.40*	*.67*	*2.25*
2018	*.83*	*.42*	*.42*	*.68*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30	.30	.32	.32	1.24
2017	.32	.32	.34		

BUSINESS: Portland General Electric Company (PGE) provides electricity to 872,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 35%; industrial, 11%; other, 7%. Generating sources: gas, 27%; coal, 16%; wind, 9%; hydro, 8%; purchased, 40%. Fuel costs: 32% of revenues. '16 reported depreciation rate: 3.5%. Has 2,700 employees. Chairman: Jack E. Davis. Chief Executive Officer: James J. Piro. President: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric has reached a settlement of its general rate case. PGE had filed for a $99.9 million (5.6%) boost in electric rates, based on a 9.75% return on a 50% common-equity ratio. The utility reached a settlement with the staff of the Oregon commission and some intervenors on all but one matter. The agreement calls for a $32 million (1.8%) hike, based on a 9.5% return (down from the current 9.6%) on a 50% common-equity ratio. The commission must still rule on the settlement. Its decision is expected in December, with new tariffs taking effect at the start of 2018.

The utility is involved in litigation related to construction of the Carty gas-fired plant. In December of 2015, PGE declared the contractor in default of the construction agreement. The plant, which went into service in July of 2016, cost $635 million. However, just $514 million of the construction costs is reflected in the company's rates. The unrecovered costs are causing a drag on profits, which PGE estimates at $0.09 a share this year. The company has filed suit against the contractor's insurers to collect a performance bond of $145.6 million, plus damages. The legal process is going slowly. Last year, management said it expects resolution of this matter will take two to four years, and one year later, PGE is still providing the same estimated time frame.

We estimate modest profit growth in 2017 and 2018. PGE benefited from favorable weather conditions in the first quarter of 2017. We are sticking with our share-earnings estimate of $2.25, which is within the company's targeted range of $2.20-$2.35. Our 2018 forecast of a mid-single-digit profit increase is based on adoption of the aforementioned regulatory settlement.

We advise investors to look elsewhere. The stock's dividend yield is a cut below the mean for electric companies. The recent quotation is near the top end of our 2020-2022 Target Price Range, possibly due to takeover speculation. Although mid-cap utilities such as PGE have attracted attention from acquirers in recent years, we do not advise investors to purchase the stock with the hope that a buyout offer will emerge.

Paul E. Debbas, CFA *October 27, 2017*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. '15 EPS don't sum due to rounding. Next earnings report due late Feb. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '16: $5.60/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '16: 9.6%; earned on avg. com. eq., '16: 8.3%. Regulatory Climate: Average. (F) '05 per-share data are pro forma, based on shs. outstanding when stock began trading in '06. (G) Summer peak in '15 & '16.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	70

SEMPRA ENERGY NYSE-SRE

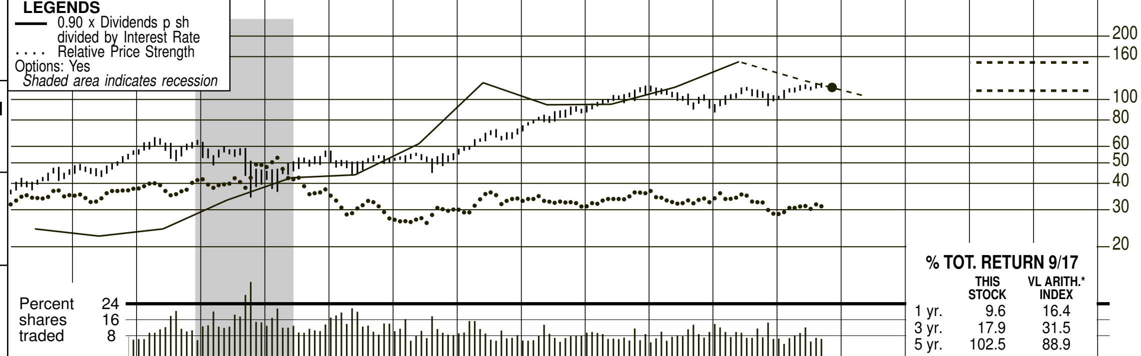
RECENT PRICE 114.04 | P/E RATIO 22.6 (Trailing: 20.8 / Median: 15.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 2 Raised 7/7/17
SAFETY 2 Raised 7/29/16
TECHNICAL 1 Raised 10/6/17
BETA .80 (1.00 = Market)

High:	57.3	66.4	63.0	57.2	57.2	56.0	72.9	93.0	116.3	116.2	114.7	120.2
Low:	42.9	50.9	34.3	36.4	43.9	44.8	54.7	70.6	86.7	89.4	86.7	99.7

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+30%)	10%
Low	110	(-5%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	1	8	0	4	0	2	0	0	0
to Sell	3	4	1	2	0	1	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	276	267	268
to Sell	242	266	259
Hld's(000)	202823	225590	223635

Percent shares traded 24 16 8

% TOT. RETURN 9/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.6	16.4
3 yr.	17.9	31.5
5 yr.	102.5	88.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
39.27	29.38	34.81	40.18	45.64	44.89	43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	40.71	*43.85*	*45.45*	Revenues per sh	*56.50*
5.39	5.71	5.56	6.58	5.96	6.74	6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.50	*10.85*	*11.55*	"Cash Flow" per sh	*15.25*
2.55	2.79	3.01	3.93	3.52	4.23	4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	4.24	*4.95*	*5.35*	Earnings per sh A	*7.25*
1.00	1.00	1.00	1.00	1.16	1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	*3.29*	*3.56*	Div'd Decl'd per sh B ■	*4.55*
5.22	5.92	4.63	4.62	5.46	7.28	7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	16.85	*13.50*	*10.45*	Cap'l Spending per sh	*11.50*
13.17	13.79	17.17	20.78	23.95	28.66	31.87	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	51.77	*53.15*	*54.85*	Book Value per sh C	*57.00*
204.48	204.91	226.60	234.18	257.19	262.01	261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	250.15	*252.00*	*254.00*	Common Shs Outst'g D	*236.00*
9.7	8.2	9.0	8.6	11.8	11.5	14.0	11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	24.4	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.50	.45	.51	.45	.63	.62	.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	*Value Line*		Relative P/E Ratio	*1.15*
4.1%	4.4%	3.7%	2.9%	2.8%	2.5%	2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $18113 mill. **Due in 5 Yrs** $7908 mill.
LT Debt $15000 mill. **LT Interest** $645 mill.
Incl. $240 mill. capitalized leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $78 mill.
Pension Assets-12/16 $2459 mill.
Oblig $3679 mill.
Pfd Stock $20 mill. **Pfd Div'd** $1.2 mill.
811,073 shs. 6% cum., $25 par.
Common Stock 251,077,626 shs.
as of 7/28/17
MARKET CAP: $29 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
11438	10758	8106.0	9003.0	10036	9647.0	10557	11035	10231	10183	*11050*	*11550*	Revenues ($mill)	*13350*
1135.0	1123.0	1193.0	1008.0	1088.0	1079.0	1060.0	1162.0	1314.0	1065.0	*1360*	*1510*	Net Profit ($mill)	*1845*
33.6%	29.2%	30.5%	26.5%	25.3%	18.2%	26.5%	19.7%	19.2%	14.4%	*29.0%*	*29.0%*	Income Tax Rate	*28.0%*
11.5%	13.2%	10.6%	11.3%	15.2%	17.2%	11.2%	14.4%	15.3%	22.2%	*26.0%*	*23.0%*	AFUDC % to Net Profit	*11.0%*
34.8%	44.5%	44.8%	49.4%	50.4%	52.8%	50.5%	51.7%	52.6%	52.7%	*53.5%*	*54.0%*	Long-Term Debt Ratio	*60.5%*
63.7%	54.2%	54.1%	49.6%	49.2%	46.7%	49.4%	48.2%	47.3%	47.3%	*46.0%*	*46.0%*	Common Equity Ratio	*39.5%*
13071	14692	16646	18186	20015	22002	22281	23513	24963	27400	*29000*	*30425*	Total Capital ($mill)	*34100*
14884	16865	18281	19876	23572	25191	25460	25902	28039	32931	*34850*	*35950*	Net Plant ($mill)	*38800*
9.6%	8.5%	8.3%	6.8%	6.7%	6.1%	6.0%	6.1%	6.4%	5.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
13.3%	13.8%	13.0%	10.9%	10.9%	10.4%	9.6%	10.2%	11.1%	8.2%	*9.5%*	*10.0%*	Return on Shr. Equity	*13.0%*
13.5%	14.0%	13.1%	11.1%	11.0%	10.4%	9.6%	10.3%	11.1%	8.2%	*9.5%*	*10.0%*	Return on Com Equity E	*13.0%*
9.7%	9.7%	9.3%	7.0%	6.5%	5.1%	4.1%	5.0%	5.8%	2.9%	*3.0%*	*3.5%*	Retained to Com Eq	*5.0%*
29%	31%	29%	37%	41%	52%	58%	52%	48%	65%	*66%*	*66%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+1.8	-1.0	-3.8
Avg. Indust. Use (MWH)	4543	4683	4785
Avg. Indust. Revs. per KWH (¢)	16.55	17.58	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.6	+.7	+.6
Fixed Charge Cov. (%)	288	295	237

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-.5%	2.5%	*5.0%*
"Cash Flow"	4.0%	4.0%	*8.0%*
Earnings	2.0%	1.0%	*7.5%*
Dividends	9.5%	11.0%	*8.5%*
Book Value	7.0%	5.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	2795	2678	2815	2747	11035
2015	2682	2367	2481	2701	10231
2016	2622	2156	2535	2870	10183
2017	3031	2533	*2586*	*2900*	*11050*
2018	*3150*	*2650*	*2700*	*3050*	*11550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.99	1.08	1.39	1.17	4.63
2015	1.74	1.03	.99	1.47	5.23
2016	1.61	.06	1.02	1.52	4.24
2017	1.75	1.20	*.95*	*1.05*	*4.95*
2018	*1.85*	*1.10*	*1.10*	*1.30*	*5.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.60	.63	.63	.63	2.49
2014	.63	.66	.66	.66	2.61
2015	.66	.70	.70	.70	2.76
2016	.70	.755	.755	.755	2.97
2017	.755	.8225	.8225	.8225	

BUSINESS: Sempra Energy is a holding co. for San Diego Gas & Electric Company, which sells electricity & gas mainly in San Diego County, & Southern California Gas Company, which distributes gas to most of Southern California. Customers: 1.4 mill. electric, 6.6 mill. gas. Electric rev. breakdown: residential, 41%; commercial, 42%; industrial, 10%; other, 7%. Purchases most of its power; the rest is gas. Has subsidiaries in gas pipeline & storage, power generation, & liquefied natural gas. Sold commodities business in '10. Power costs: 38% of revs. '16 reported deprec. rates: 2.4%-6.6%. Has 17,400 employees. Chairman, President and CEO: Debra L. Reed. Inc.: California. Address: 488 8th Avenue, San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy has announced a major acquisition. The company has agreed to pay $9.45 billion in cash for Energy Future Holdings, the 80%-owner of Oncor, a transmission and distribution electric utility in Texas. The purchase has already been approved by the bankruptcy court — Energy Future is in Chapter 11 proceedings—and requires the approval of the Texas commission and the Federal Energy Regulatory Commission. Sempra plans to finance the transaction with 65% equity and 35% debt. The company expects to complete the deal in the first half of 2018. It also expects it to be accretive to earnings next year (even after merger-related expenses). Sempra estimates the four-year average annual accretion will be $0.10-$0.20 a share. We will not adjust our estimates and projections to reflect the acquisition until after it has been completed, but we are including merger-related costs. These expenses are not reflected in Sempra's earnings guidance of $4.95-$5.25 for 2017 and $5.30-$5.80 for 2018.

A large construction project is experiencing delays. The Cameron liquefied natural gas export facility was originally supposed to be completed in 2018, but won't be finished until 2019. Management still projects $300 million-$350 million of net profit for this project in its first full year of operation, but that year will be 2020, not 2019.

We estimate significant earnings increases this year and next. Some of this year's improvement is due to the easy comparison in the June quarter. (Last year, Sempra booked an aftertax charge of $123 million in the period to reflect the early release of pipeline capacity for an asset it sold.) Some of it is due to new investments and solid performances in the company's lines of business. In fact, Sempra did not reduce its 2018 earnings target, despite the fact that the company will get no income from Cameron next year.

The dividend yield of this timely stock is low, by utility standards. This reflects Sempra's superior dividend growth potential, as well as the fact that the company is not a pure utility. The stock's total return potential to 2020-2022 is just modest, but still better than that of most equities in this industry.

Paul E. Debbas, CFA *October 27, 2017*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, '06, $1.21; '07, (10¢). '14 & '16 EPS don't sum due to rounding or chg. in shs. Next egs. due early Nov. (B) Div'ds pd. mid-Jan., Apr., July, Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '16: $25.29/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '13: 10.3%; SoCalGas in '13: 10.1%; earn. on avg. com. eq., '16: 8.6%. Reg. Clim.: Avg. (6¢); '09, (26¢); '10, ($1.05); '11, $1.15; '12, (98¢); '13, (30¢); '15, 14¢; '16, $1.23; '17, (17¢); gain (loss) from disc. ops.:

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	80

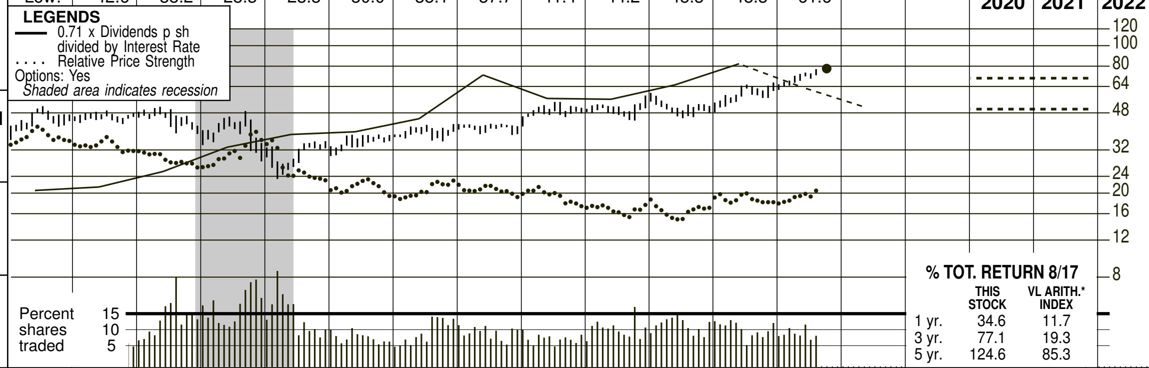
ALLETE NYSE-ALE

RECENT PRICE 77.83 | P/E RATIO 23.4 (Trailing: 23.0 / Median: 16.0) | RELATIVE P/E RATIO 1.24 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 1 Raised 9/1/17
SAFETY 2 New 10/1/04
TECHNICAL 4 Lowered 9/1/17
BETA .75 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	78.1	
Low:	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6	

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(-10%)	1%
Low	50	(-35%)	-6%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	8	0	0	0	0	8	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	129	123	149
to Sell	104	111	87
Hld's(000)	36120	36294	43766

% TOT. RETURN 8/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.6	11.7
3 yr.	77.1	19.3
5 yr.	124.6	85.3

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	*28.75*	*29.55*	Revenues per sh	*32.25*
--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	*7.30*	*7.75*	"Cash Flow" per sh	*9.00*
--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	*3.30*	*3.55*	Earnings per sh A	*4.25*
--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	*2.14*	*2.22*	Div'd Decl'd per sh B ■ †	*2.50*
--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	*4.60*	*7.50*	Cap'l Spending per sh	*3.50*
--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	*39.85*	*41.35*	Book Value per sh C	*46.50*
--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	*51.00*	*51.30*	Common Shs Outst'g D	*52.50*
--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.99	*Value Line*		Relative P/E Ratio	*.90*
--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $1519.1 mill. **Due in 5 Yrs** $504.9 mill.
LT Debt $1401.4 mill. **LT Interest** $59.3 mill.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $13.7 mill.

Pension Assets-12/16 $557.5 mill. **Oblig** $743.3 mill.

Pfd Stock None

Common Stock 50,956,836 shs.

MARKET CAP: $4.0 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	1486.4	1339.7	*1465*	*1515*	Revenues ($mill)	*1690*
87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	163.4	155.3	*165*	*185*	Net Profit ($mill)	*225*
34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	42.0%	*41.0%*	*41.0%*	Long-Term Debt Ratio	*39.0%*
64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	*59.0%*	*59.0%*	Common Equity Ratio	*61.0%*
1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	*3455*	*3600*	Total Capital ($mill)	*4025*
1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	*3770*	*3940*	Net Plant ($mill)	*4025*
8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	*8.0%*	*8.5%*	Return on Com Equity E	*9.0%*
5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	2.8%	*3.0%*	*3.5%*	Retained to Com Eq	*4.0%*
51%	61%	93%	81%	66%	71%	72%	67%	60%	66%	*64%*	*62%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+.5	-8.9	-2.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.09	6.40	NA
Capacity at Peak (Mw)	1985	1942	NA
Peak Load, Winter (Mw)	1637	1631	1520
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	345	381	318

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	1.0%	2.5%	*3.5%*
"Cash Flow"	6.0%	9.0%	*7.0%*
Earnings	3.5%	7.0%	*6.0%*
Dividends	7.5%	2.5%	*4.0%*
Book Value	5.5%	6.0%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	296.5	260.7	288.9	290.7	1136.8
2015	320.0	323.3	462.5	380.6	1486.4
2016	333.8	314.8	349.6	341.5	1339.7
2017	365.6	353.3	*380*	*366.1*	*1465*
2018	*370*	*370*	*395*	*380*	*1515*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	.80	.40	.97	.73	2.90
2015	.85	.46	1.23	.83	3.38
2016	.93	.50	.81	.89	3.14
2017	.97	.72	*.83*	*.78*	*3.30*
2018	*1.00*	*.65*	*1.00*	*.90*	*3.55*

QUARTERLY DIVIDENDS PAID B ■ †

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	2.02
2016	.52	.52	.52	.52	2.08
2017	.535	.535	.535		

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 49%; wind, 12%; other, 6%; purchased, 33%. Fuel costs: 25% of revs. '16 deprec. rate: 3.7%. Has 2,000 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's primary utility subsidiary has a rate case pending. Minnesota Power has revised its request, and is now seeking a tariff increase of $49 million (7.7%), based on a return of 10.25% on a common-equity ratio of 53.8%. The utility is currently benefiting from an interim increase of $32.2 million, which is subject to refund.

The company's utility in Wisconsin has received a rate increase. Superior Water, Light & Power was granted an increase of $2.5 million, based on a return of 10.5% on a common-equity ratio of 55%. New tariffs took effect in the third quarter.

Minnesota Power has begun construction of a transmission line from northern Minnesota to the Canadian border. Completion of the project is expected in 2020 at a cost of $300 million-$350 million. However, there were delays this year (partly weather related), so the utility expects its capital spending for this project to wind up at $60 million this year—half of the original plan. Because Minnesota Power receives current cost recovery on its transmission expenditures, this will make earnings in the second half of 2017 below what they otherwise would have been. Despite the likelihood of lower profits in the second half . . .

Earnings are likely to increase in 2017. The interim rate increase is helping. Minnesota Power is experiencing some load growth from mining customers. And ALLETE's nonutility subsidiaries are increasing their contribution. The renewable energy business is benefiting from expansion of projects and repowering of other projects. Our 2017 earnings estimate is within ALLETE's targeted range of $3.15-$3.40 a share.

We forecast further profit growth in 2018. Current cost recovery for transmission and environmental projects, volume growth at Minnesota Power, and increased income from the nonregulated operations should boost the bottom line.

This timely stock has a dividend yield that is a cut below the industry average. With the recent quotation above our 2020-2022 Target Price Range, we do not recommend this equity for long-term investors.

Paul E. Debbas, CFA September 15, 2017

(A) Diluted EPS. Excl. nonrec. losses: '04, 25¢ net; '05, $1.84; '15, 46¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '16: $11.55/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '16: 8.3%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	85

ALLIANT ENERGY NYSE-LNT

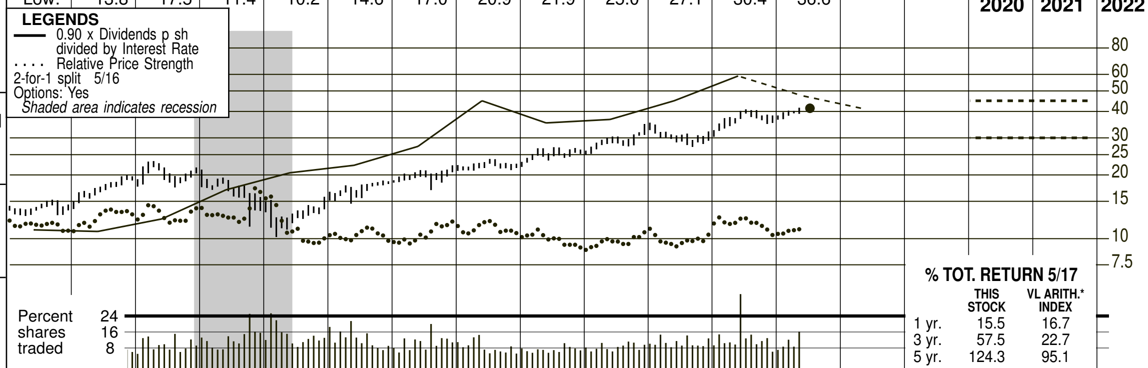
RECENT PRICE	41.46	P/E RATIO	20.7 (Trailing: 25.0 / Median: 15.0)	RELATIVE P/E RATIO	1.05	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS	3 Lowered 11/18/16
SAFETY	2 Raised 9/28/07
TECHNICAL	3 Raised 5/5/17
BETA .70 (1.00 = Market)	

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	20.0	23.3	21.2	15.8	18.8	22.2	23.8	27.1	34.9	35.4	41.0	41.9
Low:	13.8	17.5	11.4	10.2	14.6	17.0	20.9	21.9	25.0	27.1	30.4	36.6

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/16
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	6%
Low	30	(-30%)	-3%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	6	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	194	192	197
to Sell	198	196	179
Hld's(000)	150673	152516	176606

Percent shares traded 24 16 8

% TOT. RETURN 5/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.5	16.7
3 yr.	57.5	22.7
5 yr.	124.3	95.1

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
15.57	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	*15.20*	*15.50*	Revenues per sh	*17.15*
2.56	2.28	2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	*4.00*	*4.15*	"Cash Flow" per sh	*5.00*
1.35	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	*2.00*	*2.12*	Earnings per sh A	*2.50*
.64	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	*1.26*	*1.34*	Div'd Decl'd per sh B ■ †	*1.58*
2.46	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	*6.10*	*6.25*	Cap'l Spending per sh	*5.30*
12.15	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	*17.45*	*17.95*	Book Value per sh C	*19.05*
220.72	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	*230.00*	*232.00*	Common Shs Outst'g D	*236.00*
15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.80	.81	.93	.80	.91	.92	.86	.87	.91	1.17	*Value Line*		Relative P/E Ratio	*.95*
3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
3437.6	3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	*3500*	*3600*	Revenues ($mill)	*4050*
320.8	280.0	208.6	303.9	304.4	337.8	382.1	385.5	380.7	373.8	*460*	*490*	Net Profit ($mill)	*590*
44.4%	33.4%	- -	30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
2.4%	- -	- -	- -	- -	- -	- -	- -	6.5%	7.0%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
32.4%	36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	52.8%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
61.9%	58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	47.2%	*48.0%*	*48.0%*	Common Equity Ratio	*48.0%*
4329.5	4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	8177.6	*7800*	*7900*	Total Capital ($mill)	*8400*
4679.9	5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	8970.2	9809.9	*10000*	*10100*	Net Plant ($mill)	*11000*
8.6%	7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	6.3%	5.6%	*5.0%*	*5.5%*	Return on Total Cap'l	*7.0%*
11.0%	9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	*11.5%*	*12.0%*	Return on Shr. Equity	*13.0%*
11.3%	9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	*11.5%*	*12.0%*	Return on Com Equity E	*13.0%*
5.9%	3.8%	.9%	3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
50%	62%	88%	64%	67%	64%	57%	59%	65%	72%	*63%*	*63%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 3/31/17
Total Debt $4320.7 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $4316.1 mill. **LT Interest** $200.0 mill.
(LT interest earned: 3.2x)

Pension Assets-12/16 $895.7 mill. **Oblig.** $1244.3 mill.
Pfd Stock $400.0 mill. **Pfd Div'd** $10.2 mill.
16,000,000 shs.

Common Stock 227,823,278 shs.

MARKET CAP: $9.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+.1	-.1	+2.0
Avg. Indust. Use (MWH)	11821	11735	11987
Avg. Indust. Revs. per KWH (¢)	6.85	6.92	7.04
Capacity at Peak (Mw)	5426	5385	5615
Peak Load, Summer (Mw)	5426	5385	5615
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.3	+1.0
Fixed Charge Cov. (%)	320	325	342

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	0.5%	-1.5%	*4.0%*
"Cash Flow"	3.5%	6.5%	*6.0%*
Earnings	5.0%	6.5%	*6.0%*
Dividends	7.5%	6.5%	*4.5%*
Book Value	4.0%	4.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	952.8	750.3	843.1	804.1	3350.3
2015	897.4	717.2	898.9	740.1	3253.6
2016	843.8	754.2	925.0	797.0	3320.0
2017	853.9	*765*	*975*	*906.1*	*3500*
2018	*880*	*810*	*1005*	*905*	*3600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.49	.28	.70	.27	1.74
2015	.44	.30	.80	.15	1.69
2016	.43	.37	.57	.28	1.65
2017	.44	*.36*	*.88*	*.32*	*2.00*
2018	*.47*	*.38*	*.92*	*.35*	*2.12*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.235	.235	.235	.235	.94
2014	.255	.255	.255	.255	1.02
2015	.275	.275	.275	.275	1.10
2016	.295	.295	.295	.295	1.18
2017	.315	.315			

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 44%; IA, 55%; MN, 1%. Elect. rev.: residential, 35%; commercial, 25%; industrial, 29%; wholesale, 9%; other, 2%. Fuel sources, 2016: coal, 44%; gas, 21%; other, 35%. Fuel costs: 49% of revs. 2016 depreciation rate: 5.9%. Estimated plant age: 14 years. Has approximately 4,000 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy has filed a rate case with the Iowa Utilities Board. The company is seeking an increase of approximately $176 million (11.6%), based on a 10.3% return on a 49% common-equity ratio. Under Iowa law, Alliant was able to implement a temporary rate hike on April 13th for $102 million (58%) of the request. The temporary rates collected are subject to refund if the board rejects the application. A final decision is expected later this year or in early 2018 (the IUB has 10 months from the date of the filing to issue a ruling). Alliant said it would use the funds to upgrade power grids and improve facilities such as the Marshalltown natural gas generating station.

The rate case should help lift earnings this year and next. The aforementioned hike plus an earlier increase at Wisconsin Power and Light ought to help boost 2017 share net by $0.35, to $2.00. *Note that last year's tally included $0.23 per share in charges related to the revaluation of the Franklin County wind farm.* In addition, Alliant is set to benefit from improved electric and gas distribution systems (thanks to investments made in previous years), as well as renewed cost-efficiency efforts. Looking ahead, we have modeled EPS of $2.12 in 2018 (+6% year over year), which is in line with management's stated 5%-7% growth target.

The company is making good progress on renewable energy. At the end of the first quarter, LNT was generating 1,200 megawatts of clean energy across three different states. It plans to invest about $1.4 billion over the next four years on various wind and solar projects to further boost its renewable portfolio.

The balance sheet is in good shape. The fixed-charge coverage is above average for the utility industry, and the capitalization ratio is healthy. Alliant merits a Financial Strength rating of A, and its stock is ranked 2 (Above Average) for Safety.

This stock has a dividend yield that is slightly below the industry mean. In addition, the equity appears expensively priced. Its price-to-earnings ratio (20.7) is well above the 10-year average of about 15. Investors may want to wait for a better entry point before deploying funds here.

Daniel Henigson *June 16, 2017*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '07, 55¢; '08, 4¢; '09, (44¢); '10, (8¢); '11, (1¢); '12, (8¢). Next earnings report due early August. **(B)** Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. **(C)** Incl. deferred chgs. In '16: $22.6 mill., $0.10/sh. **(D)** In millions, adjusted for split. **(E)** Rate base: Orig. cost. Rates all'd on com. eq. in IA in '16: 10.5%; in WI in '16 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	95
Earnings Predictability	85

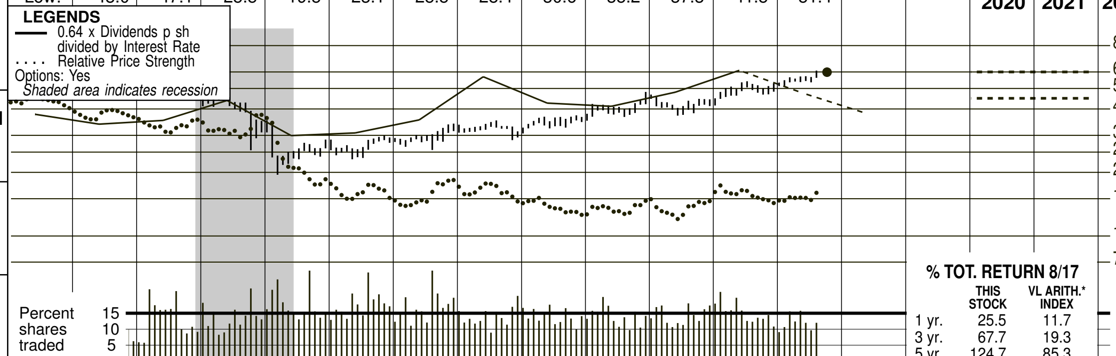
AMEREN NYSE-AEE

RECENT PRICE	59.86	P/E RATIO	20.8 (Trailing: 20.9 Median: 15.0)	RELATIVE P/E RATIO	1.10	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS 2 Raised 8/18/17
SAFETY 2 Raised 6/20/14
TECHNICAL 4 Raised 9/15/17
BETA .65 (1.00 = Market)

High:	55.2	55.0	54.3	35.3	29.9	34.1	35.3	37.3	48.1	46.8	54.1	60.8
Low:	48.0	47.1	25.5	19.5	23.1	25.5	28.4	30.6	35.2	37.3	41.5	51.4

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(Nil)	3%
Low	45	(-25%)	-3%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	10	11	0	0	0	1	0
to Sell	1	0	1	0	4	0	0	1	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	200	222	237
to Sell	205	228	205
Hld's(000)	162586	169889	191604

% TOT. RETURN 8/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.5	11.7
3 yr.	67.7	19.3
5 yr.	124.7	85.3

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	***26.15***	***27.00***	Revenues per sh	***29.50***
6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	***6.95***	***7.40***	"Cash Flow" per sh	***9.00***
3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	***2.80***	***3.00***	Earnings per sh A	***3.50***
2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	***1.78***	***1.84***	Div'd Decl'd per sh B ■	***2.15***
7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	***9.15***	***9.05***	Cap'l Spending per sh	***8.75***
24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	***30.30***	***31.50***	Book Value per sh C	***35.75***
138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	***242.63***	***242.63***	Common Shs Outst'g D	***242.63***
12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	*Bold figures are*		Avg Ann'l P/E Ratio	***14.5***
.62	.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.97	*Value Line*		Relative P/E Ratio	***.90***
6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	*estimates*		Avg Ann'l Div'd Yield	***4.2%***

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
7546.0	7839.0	7090.0	7638.0	7531.0	6828.0	5838.0	6053.0	6098.0	6076.0	***6350***	***6550***	Revenues ($mill)	***7150***
629.0	615.0	624.0	669.0	602.0	589.0	518.0	593.0	585.0	659.0	***690***	***735***	Net Profit ($mill)	***885***
33.5%	33.7%	34.7%	36.8%	37.3%	36.9%	37.5%	38.9%	38.3%	36.7%	***39.5%***	***38.0%***	Income Tax Rate	***38.0%***
.8%	4.6%	5.8%	7.8%	5.6%	6.1%	7.1%	5.7%	5.1%	4.1%	***4.0%***	***4.0%***	AFUDC % to Net Profit	***3.0%***
45.0%	47.8%	49.7%	48.2%	45.3%	49.5%	45.2%	47.2%	49.3%	47.7%	***48.0%***	***48.5%***	Long-Term Debt Ratio	***48.5%***
53.4%	50.8%	49.1%	50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	***51.0%***	***50.5%***	Common Equity Ratio	***50.5%***
12654	13712	15991	15185	14738	13384	12190	12975	13968	13840	***14350***	***15050***	Total Capital ($mill)	***17100***
15069	16567	17610	17853	18127	16096	16205	17424	18799	20113	***21325***	***22450***	Net Plant ($mill)	***25200***
6.2%	5.7%	5.3%	6.0%	5.6%	6.0%	5.6%	5.8%	5.3%	6.0%	***6.0%***	***6.0%***	Return on Total Cap'l	***6.5%***
9.0%	8.6%	7.8%	8.5%	7.5%	8.7%	7.7%	8.7%	8.3%	9.1%	***9.0%***	***9.5%***	Return on Shr. Equity	***10.0%***
9.2%	8.7%	7.8%	8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	***9.5%***	***9.5%***	Return on Com Equity E	***10.0%***
1.3%	1.0%	3.5%	3.8%	2.8%	3.0%	1.9%	2.9%	2.5%	3.3%	***3.5%***	***3.5%***	Retained to Com Eq	***4.0%***
86%	88%	56%	56%	63%	66%	76%	67%	70%	64%	***64%***	***62%***	All Div'ds to Net Prof	***60%***

CAPITAL STRUCTURE as of 6/30/17
Total Debt $8291 mill. **Due in 5 Yrs** $3444 mill.
LT Debt $6821 mill. **LT Interest** $333 mill.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/16 $3813 mill. **Oblig** $4518 mill.
Pfd Stock $142 mill. **Pfd Div'd** $6 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 242,634,798 shs. **as of 7/31/17**
MARKET CAP: $15 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-.1	-1.1	-4.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.46	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	355	343	351

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-2.0%	-4.0%	*3.0%*
"Cash Flow"	.5%	- -	*6.5%*
Earnings	-1.5%	-1.5%	*6.0%*
Dividends	-4.0%	1.5%	*4.5%*
Book Value	-1.0%	-2.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1594	1419	1670	1370	6053.0
2015	1556	1401	1833	1308	6098.0
2016	1434	1427	1859	1356	6076.0
2017	1514	1538	***1898***	***1400***	***6350***
2018	***1550***	***1600***	***1950***	***1450***	***6550***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.40	.62	1.20	.19	2.40
2015	.45	.40	1.41	.12	2.38
2016	.43	.61	1.52	.13	2.68
2017	.42	.79	***1.34***	***.25***	***2.80***
2018	***.50***	***.70***	***1.50***	***.30***	***3.00***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.40	.40	.40	.40	1.60
2014	.40	.40	.40	.41	1.61
2015	.41	.41	.41	.425	1.66
2016	.425	.425	.425	.44	1.72
2017	.44	.44			

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Acq'd CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric rev. breakdown: residential, 45%; commercial, 33%; industrial, 12%; other, 10%. Generating sources: coal, 66%; nuclear, 23%; hydro, 3%; purchased & other, 8%. Fuel costs: 28% of revs. '16 reported deprec. rates: 3%-4%. Has 8,600 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

We estimate that Ameren's earnings will advance 4% in 2017. Ameren Missouri is benefiting from a $92 million rate hike that took effect at the start of the second quarter. Ameren also has forward-looking regulatory mechanisms for its Illinois electric utility and its federally regulated transmission business that add to its income each year. Our earnings estimate, which we raised by $0.05 a share, is within the company's target of $2.70-$2.90. Note that our earnings presentation *includes* a $0.06-a-share noncash charge that Ameren will take in the current quarter for the revaluation of deferred taxes following a hike on income taxes in Illinois. This was partially offset by hotter-than-normal weather patterns in July.

We forecast a 7% earnings increase next year. This is within Ameren's goal of 5%-8% yearly profit growth. The aforementioned tariff hike in Missouri will help the March-quarter comparison. Also, the Callaway nuclear plant will not have a refueling outage in 2018. And the company will benefit from the refinancing of debt at Ameren Missouri. We have raised our estimate by $0.05 a share, to $3.00.

Ameren is awaiting a ruling from the Federal Energy Regulatory Commission (FERC) on the allowed return on equity for transmission. Following some customer complaints, allowed ROEs for transmission in the company's region were lowered. A recommendation from an administrative law judge would cut them again, from 10.82% to 10.2% (including a half percentage point "adder"). When FERC will issue its ruling is unknown.

We expect a dividend increase in the fourth quarter. This has been the board's practice in recent years. We estimate the directors will boost the annual payout by $0.06 a share (3.4%), the same increase as in each of the past two years. Ameren's target is a payout ratio in a range of 55%-70%.

This timely equity has a dividend yield that is slightly below the utility average. Like many utility issues, the recent quotation is around the upper end of our 2020-2022 Target Price Range. Thus, assuming that utility stocks trade at a more-normal valuation 3 to 5 years out, total return potential is zero.

Paul E. Debbas, CFA *September 15, 2017*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); gain (loss) from disc. ops.: '13, (92¢); '15, 21¢. '14 & '16 EPS don't sum due to rounding. Next egs. report due early Nov. (B) Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '16: $7.62/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd on com. eq. in MO in '17: elec., none specified; in '11: gas, none spec.; in IL in '14: elec., 8.7%, in '16: gas, 9.6%; earned on avg. com. eq., '16: 9.3%. Reg. Climate: Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	80

CMS ENERGY CORP. NYSE-CMS

RECENT PRICE	48.43	P/E RATIO	21.6 (Trailing: 24.3 Median: 16.0)	RELATIVE P/E RATIO	1.14	DIV'D YLD	2.9%	VALUE LINE

TIMELINESS **4** Lowered 9/1/17

SAFETY **2** Raised 3/21/14

TECHNICAL **5** Lowered 9/8/17

BETA .65 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	17.0	19.5	17.5	16.1	19.3	22.4	25.0	30.0	36.9	38.7	46.3	48.9
Low:	12.1	15.0	8.3	10.0	14.1	17.0	21.1	24.6	26.0	31.2	35.0	41.1

2020-22 PROJECTIONS

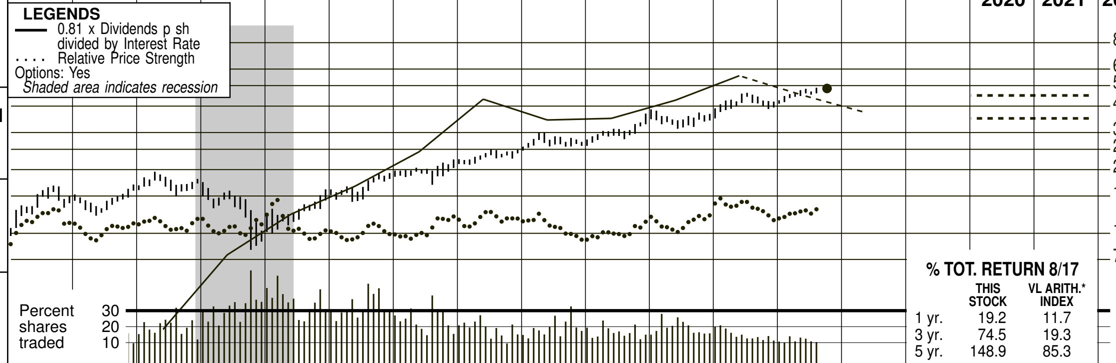
	Price	Gain	Ann'l Total Return
High	45	(-5%)	*2%*
Low	35	(-30%)	*-3%*

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	11	0	10	0	11	0	0
to Sell	0	0	0	1	1	0	5	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	203	232	254
to Sell	225	218	212
Hld's(000)	246256	246703	273887



% TOT. RETURN 8/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.2	11.7
3 yr.	74.5	19.3
5 yr.	148.9	85.3

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
72.16	60.28	34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	25.59	23.90	24.68	26.09	23.29	22.92	*23.15*	*23.85*	Revenues per sh	*26.00*
5.24	d.09	2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.65	3.82	4.06	4.22	4.59	4.88	*5.30*	*5.65*	"Cash Flow" per sh	*7.00*
1.27	d2.99	d.29	.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.53	1.66	1.74	1.89	1.98	*2.15*	*2.30*	Earnings per sh A	*2.75*
1.46	1.09	- -	- -	- -	- -	.20	.36	.50	.66	.84	.96	1.02	1.08	1.16	1.24	*1.33*	*1.42*	Div'd Decl'd per sh B ■	*1.70*
9.49	5.18	3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	3.47	4.65	4.98	5.73	5.64	5.99	*6.55*	*6.65*	Cap'l Spending per sh	*6.25*
14.21	7.86	9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	*16.25*	*17.35*	Book Value per sh C	*21.00*
132.99	144.10	161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	254.10	264.10	266.10	275.20	277.16	279.21	*281.00*	*283.00*	Common Shs Outst'g D	*289.00*
20.8	- -	- -	12.4	12.6	22.2	26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
1.07	- -	- -	.66	.67	1.20	1.42	.66	.91	.80	.85	.96	.92	.91	.92	1.11	*Value Line*		Relative P/E Ratio	*.90*
5.5%	7.5%	- -	- -	- -	- -	1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	3.4%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
						6519.0	6821.0	6205.0	6432.0	6503.0	6312.0	6566.0	7179.0	6456.0	6399.0	*6500*	*6750*	Revenues ($mill)	*7500*
						168.0	300.0	231.0	356.0	384.0	413.0	454.0	479.0	525.0	553.0	*610*	*660*	Net Profit ($mill)	*810*
						37.6%	31.6%	34.6%	38.1%	36.8%	39.4%	39.9%	34.3%	34.0%	33.1%	*33.0%*	*34.0%*	Income Tax Rate	*33.0%*
						3.6%	1.3%	13.0%	2.2%	2.6%	2.9%	2.0%	2.3%	2.7%	3.1%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
						70.5%	69.4%	67.9%	70.1%	66.9%	67.9%	67.5%	68.7%	68.3%	67.1%	*66.5%*	*65.5%*	Long-Term Debt Ratio	*64.5%*
						25.9%	27.4%	29.0%	29.5%	32.6%	31.6%	32.2%	31.0%	31.4%	32.6%	*33.5%*	*34.0%*	Common Equity Ratio	*35.5%*
						8212.0	8993.0	8977.0	9473.0	9279.0	10101	10730	11846	12534	13040	*13700*	*14450*	Total Capital ($mill)	*17100*
						8728.0	9190.0	9682.0	10069	10633	11551	12246	13412	14705	15715	*16675*	*17600*	Net Plant ($mill)	*19800*
						4.5%	5.4%	4.7%	5.8%	6.3%	5.9%	6.0%	5.7%	5.7%	5.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
						6.9%	10.9%	8.0%	12.5%	12.5%	12.8%	13.0%	12.9%	13.2%	12.9%	*13.0%*	*13.5%*	Return on Shr. Equity	*13.5%*
						7.2%	11.7%	8.5%	12.5%	12.6%	12.9%	13.1%	13.0%	13.3%	13.0%	*13.5%*	*13.5%*	Return on Com Equity E	*13.5%*
						5.1%	8.4%	4.1%	6.9%	5.6%	5.0%	5.2%	5.0%	5.2%	4.8%	*5.0%*	*5.0%*	Retained to Com Eq	*5.5%*
						35%	31%	54%	46%	55%	61%	60%	62%	61%	63%	*61%*	*61%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $10030 mill. **Due in 5 Yrs** $4210 mill.
LT Debt $9190 mill. **LT Interest** $404 mill.
Incl. $104 mill. capitalized leases.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $20 mill.
Pension Assets-12/16 $2101 mill. **Oblig** $2562 mill.
Pfd Stock $37 mill. **Pfd Div'd** $2 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00.
Common Stock 282,012,704 shs.
as of 7/11/17
MARKET CAP: $14 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+1.9	-.8	+1.7
Avg. Indust. Use (MWH)	NMF	5922	6031
Avg. Indust. Revs. per KWH (¢)	8.29	8.07	7.76
Capacity at Peak (Mw)	8776	8762	8331
Peak Load, Summer (Mw)	7498	7812	8227
Annual Load Factor (%)	59.7	55.5	54.6
% Change Customers (yr-end)	- -	+.6	+.5
Fixed Charge Cov. (%)	278	288	292

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-2.0%	-1.5%	*1.5%*
"Cash Flow"	3.5%	5.0%	*7.5%*
Earnings	8.5%	8.5%	*6.5%*
Dividends	- -	11.5%	*6.5%*
Book Value	3.0%	4.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	2523	1468	1430	1758	7179.0
2015	2111	1350	1486	1509	6456.0
2016	1801	1371	1587	1640	6399.0
2017	1829	1449	*1572*	*1650*	*6500*
2018	*1900*	*1550*	*1600*	*1700*	*6750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.75	.30	.34	.35	1.74
2015	.73	.25	.53	.38	1.89
2016	.59	.45	.67	.28	1.98
2017	.71	.33	*.67*	*.44*	*2.15*
2018	*.80*	*.40*	*.65*	*.45*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2013	.255	.255	.255	.255	1.02
2014	.27	.27	.27	.27	1.08
2015	.29	.29	.29	.29	1.16
2016	.31	.31	.31	.31	1.24
2017	.3325	.3325	.3325		

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.7 million gas customers. Has 1,034 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 45%; commercial, 31%; industrial, 18%; other, 6%. Generating sources: coal, 27%; gas, 16%; other, 3%; purchased, 54%. Fuel costs: 44% of revenues. '16 reported deprec. rates: 3.9% electric, 2.9% gas, 9.8% other. Has 7,400 employees. Chairman: John G. Russell. President & CEO: Patricia K. Poppe. Incorporated: Michigan. Address: One Energy Plaza, Jackson, MI 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary has received a gas rate order. The Michigan Public Service Commission (MPSC) raised Consumers Energy's gas rates by $29 million, based on a 10.1% return on equity. The MPSC also approved an infrastructure recovery mechanism for certain kinds of capital expenditures. This will enable the utility to earn a return on this spending without having to file a general rate case. New tariffs took effect on August 7th. Consumers Energy plans to file its next gas rate case this fall, with a final order due from the MPSC 10 months later. This will be the company's first filing under Michigan's new regulatory law, which does not have a self-implementation provision.

Consumers Energy has an electric rate case pending. The utility filed for an increase of $173 million, based on a 10.5% ROE. However, the MPSC's staff is proposing a hike of just $17 million, based on a 9.8% ROE. Consumers Energy plans to self-implement an interim increase of $130 million on October 1st, and the MPSC's order is due by the end of March.

The utility should soon receive a ruling from the MPSC regarding a buy-out of a purchased-power contract from the owner of the Palisades nuclear unit. Consumers Energy agreed to pay Entergy $172 million to buy out the above-market contract, which was set to run through 2022, but will now end in 2018. The utility intends to finance the payment by issuing securitized bonds. The MPSC's order is due by September 28th.

We expect steady earnings improvement this year and next. Rate relief is a key factor. Consumers Energy is also experiencing modest volume growth (at least when weather patterns are normal). The company's one major nonutility asset, a nonregulated power plant, is increasing its income thanks to improved performance. Our 2017 estimate is within CMS Energy's typically narrow guidance of $2.14-$2.18 a share. For 2018, we look for a 7% increase in profits, which is within management's goal of 6%-8% earnings growth.

We consider this untimely stock expensively priced. It is trading at a market premium, and the recent price is above our 2020-2022 Target Price Range. The dividend yield is below the utility average.

Paul E. Debbas, CFA *September 15, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢. '16 EPS don't sum due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '16: $7.49/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '17: 10.1%; earned on avg. com. eq., '16: 13.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	85

DTE ENERGY CO. NYSE-DTE

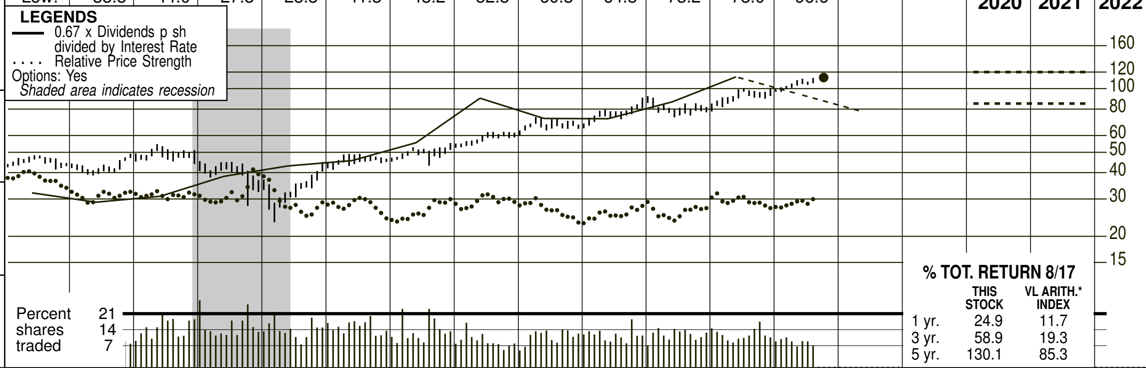
RECENT PRICE 112.77 | P/E RATIO 20.6 (Trailing: 19.3 Median: 16.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 8/25/17
SAFETY 2 Raised 12/21/12
TECHNICAL 4 Lowered 9/8/17
BETA .65 (1.00 = Market)

High:	49.2	54.7	45.3	45.0	49.1	55.3	62.6	73.3	90.8	92.3	100.4	112.8	
Low:	38.8	44.0	27.8	23.3	41.3	43.2	52.5	60.3	64.8	73.2	78.0	96.6	

Target Price Range 2020 | 2021 | 2022

LEGENDS
—— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+5%)	*5%*
Low	85	(-25%)	*-3%*

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	1	0	0	0	0	0
Options	1	0	7	12	0	0	1	0	2
to Sell	2	2	0	2	1	0	2	2	1

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	262	272	239
to Sell	196	244	261
Hld's(000)	119482	123429	138535

% TOT. RETURN 8/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.9	11.7
3 yr.	58.9	19.3
5 yr.	130.1	85.3

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
48.71	40.30	41.76	40.84	50.74	50.93	54.28	57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	*67.70*	*71.30*	Revenues per sh	*79.00*
6.98	8.31	6.95	6.81	8.14	8.19	8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	*12.05*	*12.55*	"Cash Flow" per sh	*14.75*
2.15	3.83	2.85	2.55	3.27	2.45	2.66	2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	*5.80*	*5.75*	Earnings per sh A	*6.75*
2.06	2.06	2.06	2.06	2.06	2.08	2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	*3.36*	*3.59*	Div'd Decl'd per sh B ■	*4.30*
6.80	5.88	4.45	5.19	5.99	7.92	7.96	8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	*16.15*	*14.50*	Cap'l Spending per sh	*14.00*
28.48	27.26	31.36	31.85	32.44	33.02	35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	*52.65*	*54.80*	Book Value per sh C	*62.75*
161.13	167.46	168.61	174.21	177.81	177.14	163.23	163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	*179.50*	*179.50*	Common Shs Outst'g D	*187.00*
19.3	11.3	13.7	16.0	13.8	17.4	18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.99	.62	.78	.85	.73	.94	.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.01	*Value Line*		Relative P/E Ratio	*.95*
5.0%	4.8%	5.3%	5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $12190 mill. **Due in 5 Yrs** $3499 mill.
LT Debt $11358 mill. **LT Interest** $461 mill.
Incl. $2 mill. capitalized leases and $756 mill. Trust Preferred Securities.
(LT interest earned: 4.0x)

Leases, Uncapitalized Annual rentals $33 mill.
Pension Assets-12/16 $4012 mill.
Oblig $5171 mill.
Pfd Stock None
Common Stock 179,393,579 shs.

MARKET CAP: $20 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
8861.0	9329.0	8014.0	8557.0	8897.0	8791.0	9661.0	12301	10337	10630	*12150*	*12800*	Revenues ($mill)	*14750*
453.0	445.0	532.0	630.0	624.0	666.0	661.0	905.0	796.0	868.0	*1045*	*1040*	Net Profit ($mill)	*1250*
25.1%	34.9%	31.6%	32.7%	35.9%	29.8%	27.5%	28.5%	25.6%	24.5%	*24.5%*	*24.5%*	Income Tax Rate	*24.5%*
7.1%	11.2%	2.6%	1.6%	1.6%	3.0%	3.5%	4.1%	4.3%	3.6%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
54.4%	56.4%	54.0%	51.3%	50.6%	48.8%	47.7%	50.0%	50.2%	55.6%	*56.0%*	*56.0%*	Long-Term Debt Ratio	*56.5%*
45.6%	43.6%	46.0%	48.7%	49.4%	51.2%	52.3%	50.0%	49.8%	44.4%	*44.0%*	*44.0%*	Common Equity Ratio	*43.5%*
12824	13736	13648	13811	14196	14387	15135	16670	17607	20280	*21475*	*22250*	Total Capital ($mill)	*26800*
11408	12231	12431	12992	13746	14684	15800	16820	18034	19730	*21500*	*22875*	Net Plant ($mill)	*26300*
5.3%	5.0%	5.7%	6.3%	5.9%	6.1%	5.7%	6.6%	5.7%	5.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
7.7%	7.4%	8.5%	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	*11.0%*	*10.5%*	Return on Shr. Equity	*10.5%*
7.7%	7.4%	8.5%	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	*11.0%*	*10.5%*	Return on Com Equity E	*10.5%*
1.5%	1.7%	2.9%	4.0%	3.4%	3.5%	2.7%	5.2%	3.4%	3.7%	*4.5%*	*4.0%*	Retained to Com Eq	*4.0%*
80%	77%	65%	57%	62%	61%	67%	52%	63%	61%	*58%*	*62%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-1.7	-.6	+3.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	357	279	300

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	2.5%	4.0%	*4.0%*
"Cash Flow"	3.5%	2.0%	*5.5%*
Earnings	5.5%	6.0%	*6.0%*
Dividends	3.5%	5.5%	*7.0%*
Book Value	4.0%	4.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3930	2698	2595	3078	12301
2015	2984	2268	2598	2487	10337
2016	2566	2262	2928	2874	10630
2017	3236	2855	*3059*	*3000*	*12150*
2018	*3400*	*3000*	*3250*	*3150*	*12800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.84	.70	.88	1.68	5.10
2015	1.53	.61	1.47	.83	4.44
2016	1.37	.84	1.88	.73	4.83
2017	2.23	.99	*1.50*	*1.08*	*5.80*
2018	*1.90*	*1.00*	*1.65*	*1.20*	*5.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.62	.62	.655	.655	2.55
2014	.655	.655	.655	.69	2.66
2015	.69	.69	.69	.73	2.80
2016	.73	.73	.73	.77	2.96
2017	.825	.825	.825		

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.1 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 48%; commercial, 34%; industrial, 13%; other, 5%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 52% of revenues. '16 reported deprec. rates: 3.5% electric, 2.4% gas. Has 10,000 employees. Chairman & CEO: Gerard M. Anderson. President & COO: Jerry Norcia. Inc.: MI. Address: One Energy Plaza, Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary has a rate case pending. DTE Electric requested an increase of $231 million, based on a return on equity of 10.5%. The staff of the Michigan Public Service Commission (MPSC) is proposing a hike of $71 million, based on a 9.8% ROE. DTE Electric will self-implement an increase (of an amount not yet determined) at the start of November. The MPSC's order is due in April. The utility also plans to file a rate application in 2018, and every year thereafter in the near future.

DTE Electric is asking the MPSC for a certificate of need to build a gas-fired plant. The 1,100-megawatt facility would cost nearly $1 billion. It would begin commercial operation in 2022, and would offset the capacity that would be lost from the retirement of three old coal-fired plants. The MPSC's ruling is due by the end of April.

DTE Gas is planning to file a rate case. This will probably occur in late 2017 and early 2018. The application will be the company's first general rate case under Michigan's new regulatory law, which provides for an order in 10 months (versus 12 previously), but no self-implementation provision.

DTE Energy is seeing growth from both the utility and nonutility sides of its business. The utilities are benefiting from rate relief and modest load growth. The nonutility operations are adding projects and assets. Most notably, the 50%-owned NEXUS gas pipeline received a key approval from the Federal Energy Regulatory Commission; another approval is still needed for construction to proceed. This project—a $1 billion investment for DTE Energy—is scheduled for completion in 2018.

We expect a dividend increase at the board meeting in the fourth quarter. We estimate the directors will raise the annual payout by $0.23 a share (7%). DTE Energy has a goal of 7% yearly dividend growth through 2019.

DTE Energy stock has a dividend yield that is slightly below the utility mean. Total return potential to 2020-2022 is low. As is true for most utility equities, the recent quotation is well within our 3- to 5-year Target Price Range.

Paul E. Debbas, CFA *September 15, 2017*

(**A**) Diluted EPS. Excl. nonrec. gains (losses): '03, (16¢); '05, (2¢); '06, 1¢; '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); gains (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢). '16 EPS don't sum due to rounding. Next egs report due late Oct. (**B**) Div'ds paid in mid-Jan., Apr., July and Oct. ■ Div'd reinvest. plan avail. (**C**) Incl. intang. In '16: $39.01/sh. (**D**) In mill. (**E**) Rate base: Net orig. cost. Rate allowed on com. eq. in '17: 10.1% elec.; in '16: 10.1% gas; earn. on avg. com. eq., '16: 4.9%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	80

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 35.80 | P/E RATIO 18.4 (Trailing: 20.6 Median: 15.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 3/3/17

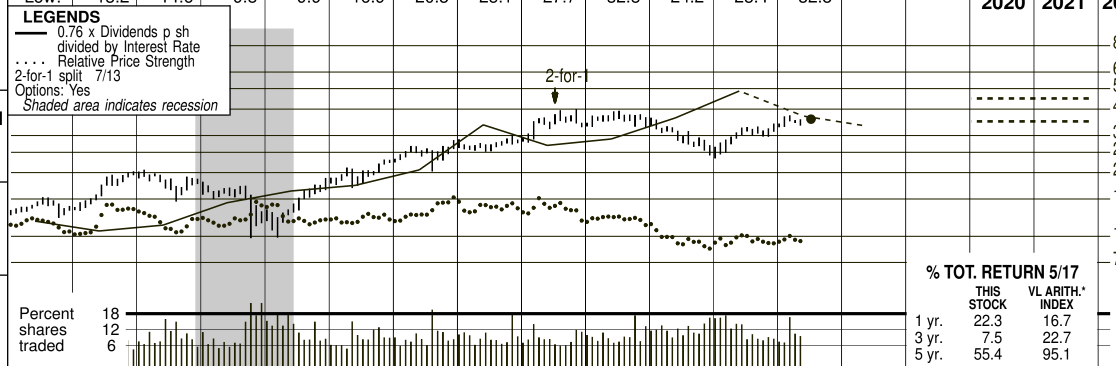
SAFETY 2 Lowered 12/18/15

TECHNICAL 3 Lowered 6/16/17

BETA .95 (1.00 = Market)

High:	20.3	20.7	18.1	18.9	23.1	28.6	30.1	40.0	39.3	36.5	34.2	37.4
Low:	13.2	14.6	9.8	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4	32.8

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	35	(Nil)	4%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	1	0	0	0	0	0	1	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	158	195	204
to Sell	152	156	162
Hld's(000)	132580	131802	148397

% TOT. RETURN 5/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.3	16.7
3 yr.	7.5	22.7
5 yr.	55.4	95.1

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
20.40	19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	**11.50**	**12.00**	Revenues per sh	**14.25**
1.81	1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	**3.40**	**3.50**	"Cash Flow" per sh	**4.25**
.65	.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	**1.95**	**2.05**	Earnings per sh A	**2.50**
.67	.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	**1.27**	**1.40**	Div'd Decl'd per sh B ■	**1.75**
1.44	1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	**4.90**	**2.95**	Cap'l Spending per sh	**1.75**
6.67	6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	**17.95**	**18.60**	Book Value per sh C	**20.50**
155.98	157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	**199.70**	**200.00**	Common Shs Outst'g D	**201.50**
17.4	14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	**16.5**
.89	.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.94	*Value Line*		Relative P/E Ratio	**1.05**
5.9%	6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	*estimates*		Avg Ann'l Div'd Yield	**4.3%**

CAPITAL STRUCTURE as of 3/31/17
Total Debt $3056.2 mill. **Due in 5 Yrs** $853.3 mill.
LT Debt $2703.2 mill. **LT Interest** $142.9 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $6.0 mill.

Pension Assets-12/16 $595.9 mill. **Oblig** $672.2 mill.

Pfd Stock None

Common Stock 199,704,099 shs.

MARKET CAP: $7.1 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
3797.6	4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	**2300**	**2400**	Revenues ($mill)	**2850**
244.2	231.4	258.3	295.3	342.9	355.0	387.6	395.8	337.6	338.2	**395**	**405**	Net Profit ($mill)	**490**
32.3%	30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	**32.0%**	**32.0%**	Income Tax Rate	**32.0%**
1.6%	1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	**13.0%**	**7.0%**	AFUDC % to Net Profit	**3.0%**
44.4%	53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	**45.5%**	**47.0%**	Long-Term Debt Ratio	**52.0%**
55.6%	46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	**55.5%**	**53.0%**	Common Equity Ratio	**48.0%**
3025.5	4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	**6590**	**7030**	Total Capital ($mill)	**8625**
4246.3	5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	**8395**	**8695**	Net Plant ($mill)	**8775**
9.5%	7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	**11.0%**	**11.0%**	Return on Shr. Equity	**12.0%**
14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	**11.0%**	**11.0%**	Return on Com Equity E	**12.0%**
7.1%	5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	4.0%	3.3%	**4.0%**	**3.5%**	Retained to Com Eq	**3.5%**
51%	55%	53%	48%	43%	44%	43%	47%	61%	67%	**64%**	**68%**	All Div'ds to Net Prof	**72%**

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-.7	-2.9	-1.1
Avg. Indust. Use (MWH)	770	754	NA
Avg. Indust. Revs. per KWH (¢)	5.73	5.05	5.17
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6339	6537	6538
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.2	+1.1
Fixed Charge Cov. (%)	356	314	336

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-8.5%	-8.5%	3.5%
"Cash Flow"	5.0%	2.0%	4.5%
Earnings	6.0%	3.5%	5.5%
Dividends	4.5%	7.5%	9.0%
Book Value	8.0%	7.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	560.4	611.8	754.7	526.2	2453.1
2015	480.1	549.9	719.8	447.1	2196.9
2016	433.1	551.4	743.9	530.8	2259.2
2017	456.0	**550**	**750**	**544**	**2300**
2018	**475**	**575**	**800**	**550**	**2400**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.25	.50	.94	.29	1.98
2015	.22	.44	.88	.15	1.69
2016	.13	.35	.92	.29	1.69
2017	.18	**.47**	**1.00**	**.30**	**1.95**
2018	**.20**	**.50**	**1.05**	**.30**	**2.05**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.209	.209	.209	.209	.84
2014	.225	.225	.225	.25	.93
2015	.25	.25	.25	.275	1.03
2016	.275	.275	.275	.3025	1.13
2017	.3025	.3025			

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 836,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.7% of Enable Midstream Partners. Electric revenue breakdown: residential, 42%; commercial, 25%; industrial, 15%; other, 18%. Generating sources: coal, 33%; gas, 31%; wind, 5%; purchased, 31%. Fuel costs: 39% of revenues. '16 reported depreciation rate (utility): 3.0%. Has 2,500 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary received a disappointing rate order in Oklahoma. The commission granted Oklahoma Gas and Electric a rate increase of just $8.8 million, based on a return of 9.5% on a common-equity ratio of 53%. This was well below the utility's request for a $92.5 million increase, based on a 10.25% ROE, and fell far short of even an administrative law judge's recommendation of a $40.7 million hike, based on a 9.87% ROE. What's more, the regulators reduced OG&E's depreciation by $36.4 million annually. This will not affect the company's earnings, but will hurt cash flow. The order was retroactive to July 1, 2016.

OG&E is hoping for a better outcome in its next rate case. This is planned for the fourth quarter, with new tariffs taking effect in mid-2018. The utility will seek recovery of a project to modernize a gas-fired generating plant, which is expected to cost $425 million.

The regulatory news was better in Arkansas. The state commission approved a settlement calling for a rate hike of $7.1 million, based on a 9.5% return on a 50% common-equity ratio. New tariffs took effect on June 1st.

We have cut our 2017 earnings estimate by $0.10 a share, to $1.95. This is due to the disappointing rate order in Oklahoma. The company now believes profits are likely to come in at the low end of its targeted range of $1.93-$2.09. We have also trimmed our 2018 forecast by $0.05 a share, to $2.05. Even this might prove optimistic if OG&E gets a disappointing ruling in its next rate case in Oklahoma.

We expect a hefty increase at the board's next dividend meeting, in late September. OGE has reiterated its expectation of 10% annual dividend growth through 2019. Despite the reduction in our earnings estimates, the company's payout ratio is still moderate for a utility. Also, OGE benefits from distributions (probably at least $140 million this year) from its 25.7% stake in Enable Midstream Partners, a natural gas master limited partnership.

This stock has a dividend yield that is slightly above the utility average. Total return potential to 2020-2022 is greater than that of most utilities.

Paul E. Debbas, CFA *June 16, 2017*

(A) Diluted EPS. Excl. nonrecurring losses: '02, 20¢; '03, 7¢; '04, 3¢; '15, 33¢; gains on discontinued operations: '02, 6¢; '05, 25¢; '06, 20¢. Next earnings report due early Aug. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '16: $2.03/sh. (D) In millions, adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '16: 9.5%; in AR in '11: 9.95%; earned on avg. com. eq., '16: 10.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	80

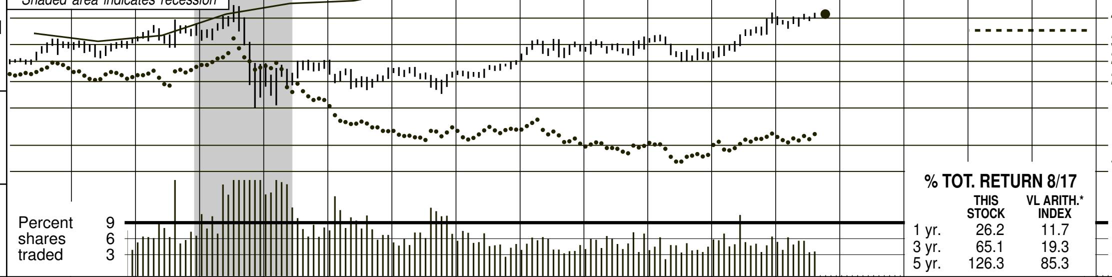
OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE **41.85** | P/E RATIO **23.8** (Trailing: 24.3 / Median: 23.0) | RELATIVE P/E RATIO **1.26** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS 3 Lowered 10/14/16
SAFETY 2 Raised 6/17/16
TECHNICAL 3 Lowered 8/25/17
BETA .90 (1.00 = Market)

High:	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4	42.6	42.3
Low:	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8	25.8	35.7

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+20%)	*7%*
Low	35	(-15%)	*-1%*

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	6	0	9	0	0	0
to Sell	1	0	1	1	1	0	1	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	80	65	68
to Sell	45	57	63
Hld's(000)	14545	15287	18320

Percent shares traded 9 6 3

% TOT. RETURN 8/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.2	11.7
3 yr.	65.1	19.3
5 yr.	126.3	85.3

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	*20.90*	*21.45*	Revenues per sh	*25.00*
3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	*3.65*	*3.90*	"Cash Flow" per sh	*4.90*
1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	*1.75*	*1.85*	Earnings per sh A	*2.30*
1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	*1.28*	*1.30*	Div'd Decl'd per sh B ■	*1.38*
2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	*3.75*	*4.65*	Cap'l Spending per sh	*2.10*
11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	*17.75*	*18.80*	Book Value per sh C	*22.25*
24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	*40.00*	*41.00*	Common Shs Outst'g D	*44.00*
16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	NMF	47.5	21.7	21.1	18.8	18.2	20.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*18.0*
.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	NMF	2.98	1.38	1.19	.99	.92	1.06	*estimates*		Relative P/E Ratio	*1.15*
3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%			Avg Ann'l Div'd Yield	*3.3%*
						1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	779.8	803.5	*835*	*880*	Revenues ($mill)	*1100*
						54.0	35.1	26.0	13.6	16.4	39.0	50.2	56.9	58.6	62.0	*70.0*	*75.0*	Net Profit ($mill)	*100*
						34.1%	30.0%	- -	- -	14.5%	5.2%	21.3%	22.5%	27.0%	24.5%	*25.0%*	*25.0%*	Income Tax Rate	*30.0%*
						4.2%	6.1%	4.0%	.6%	3.8%	1.7%	- -	- -	1.7%	3.6%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
						38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	42.4%	43.0%	*42.5%*	*41.5%*	Long-Term Debt Ratio	*41.0%*
						59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	57.0%	*57.5%*	*58.5%*	Common Equity Ratio	*59.0%*
						882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	1051.0	1175.4	*1235*	*1320*	Total Capital ($mill)	*1655*
						854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	1387.8	1477.2	*1525*	*1600*	Net Plant ($mill)	*1900*
						7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	6.7%	6.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
						10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	9.7%	9.3%	*9.5%*	*9.5%*	Return on Shr. Equity E	*10.0%*
						10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.3%	*9.5%*	*9.5%*	Return on Com Equity	*10.0%*
						3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	2.0%	2.1%	*2.5%*	*2.5%*	Retained to Com Eq	*4.0%*
						66%	108%	NMF	NMF	NMF	113%	87%	78%	79%	78%	*74%*	*72%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $590.7 mill. **Due in 5 Yrs** $232.0 mill.
LT Debt $490.4 mill. **LT Interest** $26.0 mill.
(LT interest earned: 3.9x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/16 $254.3 mill. **Oblig.** $314.6 mill.
Pfd Stock None

Common Stock 39,557,391 shs.
as of 7/31/17
MARKET CAP: $1.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+4.6	-2.2	3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	336	350	348

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-5.0%	-7.0%	*3.0%*
"Cash Flow"	- -	4.5%	*7.0%*
Earnings	-.5%	25.0%	*6.5%*
Dividends	1.0%	.5%	*2.0%*
Book Value	- -	-1.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	215.0	194.4	196.5	193.4	799.3
2015	202.8	188.2	200.0	188.8	779.8
2016	206.2	203.5	197.2	196.6	803.5
2017	214.1	212.1	*204*	*204.8*	*835*
2018	*225*	*225*	*215*	*215*	*880*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.59	.27	.43	.28	1.55
2015	.37	.36	.42	.41	1.56
2016	.38	.41	.37	.44	1.60
2017	.49	.42	*.40*	*.44*	*1.75*
2018	*.50*	*.44*	*.43*	*.48*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308	.308	1.23
2016	.313	.313	.313	.313	1.25
2017	.320	.320	.320		

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (53% of retail elec. revs.), North Dakota (38%), and South Dakota (9%). Electric rev. breakdown, '16: residential, 31%; commercial & farms, 36%; industrial, 31%; other, 2%. Fuel costs: 14.7% of revenues. Also has operations in manufacturing and plastics. 2016 depr. rate: 3.3%. Has 2,054 employees. Off. and dir. own 1.4% of common stock; Cascade Investment, LLC, 8.8%; The Vanguard Group, 8.3%; BlackRock, Inc., 6.3% (3/17 Proxy). Chairman: Nathan I. Partain. CEO: Charles S. MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Web: www.ottertail.com.

Shares of Otter Tail have edged higher over the past three months. The company reported solid results for the June quarter. The top line advanced roughly 4%, on a year-to-year basis. Earnings per share of $0.42 came in slightly ahead of the prior-year tally. Performance was driven by favorable results from the Electric and Plastics businesses. The utility benefited from greater transmission service revenues and lower plant operating and maintenance costs, while margins improved at the company's PVC pipe subsidiaries. Earnings declined slightly at the Manufacturing segment, however. This was due to greater costs for scrapped parts and obsolete inventory, as well as an unfavorable product mix, at BTD Manufacturing in the recent period. Looking forward, we anticipate favorable comparisons for the September period, and greater revenues and earnings per share for the company in full-year 2017.

Investment in operations should continue to benefit results from 2018 onward. Otter Tail expects to invest $862 million through 2021. These outlays ought to produce annual growth in the utility rate base of 7.5% during this time period. Investments include two regional transmission projects (mentioned below) as well as new natural gas and wind generation. The company's two 345-kilovolt transmission projects remain on schedule and on budget. The Big Stone South-Brookings line is scheduled for completion later this year, and the Big Stone South-Ellendale line is expected to be finished in 2019. Otter Tail is a 50% owner in both projects. These provide an immediate return on invested funds through rider recovery mechanisms. Elsewhere, efforts by the company's Manufacturing businesses to improve operations ought to bear fruit.

This stock is ranked to perform in line with the broader market averages for the coming six to 12 months. The shares do not stand out for long-term total return potential, either. The dividend yield is respectable for a utility, however. Conservative, income-seeking subscribers might prefer to wait for a pullback in the stock price. Otter Tail earns favorable marks for Safety, Financial Strength, and Price Stability.

Michael Napoli, CFA *September 15, 2017*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢. Earnings may not sum due to rounding. Next earnings report due late October/early November. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '16: $52.5 mill., $1.34/sh. (D) In mill. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	30
Earnings Predictability	55

VECTREN CORP. NYSE-VVC

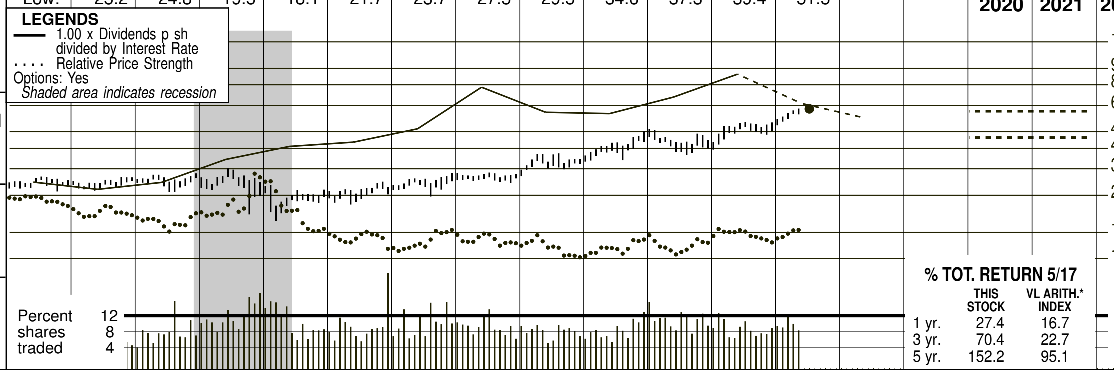
RECENT PRICE **61.64** | P/E RATIO **23.3** (Trailing: 23.3 Median: 16.0) | RELATIVE P/E RATIO **1.18** | DIV'D YLD **2.8%** | VALUE LINE

TIMELINESS **3** Raised 6/9/17
SAFETY **2** Lowered 1/5/01
TECHNICAL **3** Raised 5/12/17
BETA .70 (1.00 = Market)

High:	29.3	30.5	32.2	26.9	27.8	30.7	30.8	37.9	48.3	49.5	53.3	62.8
Low:	25.2	24.8	19.5	18.1	21.7	23.7	27.5	29.5	34.6	37.3	39.4	51.5

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(-5%)	2%
Low	45	(-25%)	-4%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	10	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	129	138	152
to Sell	136	132	130
Hld's(000)	51679	52408	60445

% TOT. RETURN 5/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.4	16.7
3 yr.	70.4	22.7
5 yr.	152.2	95.1

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren.

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
29.88	30.67	25.76	26.06	28.39	27.16	30.23	31.62	29.40	29.53	*30.20*	*31.25*	Revenues per sh	*38.35*
4.29	3.97	4.40	4.44	4.71	5.03	5.03	5.33	5.48	5.69	*5.85*	*6.20*	"Cash Flow" per sh	*7.75*
1.83	1.63	1.79	1.65	1.73	1.94	1.66	2.02	2.39	2.55	*2.65*	*2.80*	Earnings per sh A	*3.35*
1.27	1.31	1.35	1.37	1.39	1.41	1.43	1.46	1.54	1.62	*1.70*	*1.78*	Div'd Decl'd per sh B■†	*2.00*
4.38	4.83	5.33	3.39	3.92	4.45	4.77	5.43	5.76	6.54	*6.70*	*7.15*	Cap'l Spending per sh	*8.70*
16.16	16.68	17.23	17.61	17.89	18.57	18.86	19.45	20.34	21.33	*22.50*	*23.80*	Book Value per sh C	*28.50*
76.36	81.03	81.10	81.70	81.90	82.20	82.40	82.60	82.80	82.90	*83.50*	*84.00*	Common Shs Outst'g D	*86.00*
15.3	16.8	12.9	15.0	15.8	15.0	20.7	20.0	17.9	19.2	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.81	1.01	.86	.95	.99	.95	1.16	1.05	.90	1.01	*Value Line*		Relative P/E Ratio	*1.00*
4.5%	4.8%	5.9%	5.5%	5.1%	4.8%	4.2%	3.6%	3.6%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
2281.9	2484.7	2088.9	2129.5	2325.2	2232.8	2491.2	2611.7	2434.7	2448.3	*2520*	*2625*	Revenues ($mill)	*3300*
143.1	129.0	145.0	133.7	141.6	159.0	136.6	166.9	197.3	211.6	*220*	*235*	Net Profit ($mill)	*290*
34.7%	37.1%	26.5%	35.8%	37.9%	34.2%	32.9%	32.7%	33.6%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.8%	2.9%	4.1%	- -	- -	- -	- -	- -	4.1%	4.0%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
50.2%	48.0%	52.4%	49.9%	51.6%	50.4%	53.3%	46.7%	50.6%	47.3%	*47.5%*	*47.5%*	Long-Term Debt Ratio	*46.0%*
49.8%	52.0%	47.6%	50.1%	48.4%	49.6%	46.7%	53.3%	49.4%	52.7%	*52.5%*	*52.5%*	Common Equity Ratio	*54.0%*
2479.1	2599.5	2937.7	2874.1	3025.1	3079.5	3331.4	3013.9	3406.6	3358.0	*3580*	*3800*	Total Capital ($mill)	*4550*
2539.7	2720.3	2878.8	2955.4	3032.6	3119.6	3224.3	3439.0	4089.5	4406.8	*4600*	*4850*	Net Plant ($mill)	*5600*
7.2%	6.5%	6.3%	6.1%	6.2%	6.4%	5.4%	6.8%	7.0%	7.4%	*7.0%*	*7.5%*	Return on Total Cap'l	*7.5%*
11.6%	9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.4%	11.7%	12.0%	*11.5%*	*12.0%*	Return on Shr. Equity	*12.0%*
11.6%	9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.4%	11.7%	12.0%	*11.5%*	*12.0%*	Return on Com Equity E	*12.0%*
3.8%	2.0%	2.6%	1.6%	1.9%	2.9%	1.2%	2.9%	4.2%	4.4%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
67%	80%	75%	83%	80%	73%	86%	72%	65%	63%	*65%*	*64%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 3/31/17
Total Debt $1815.7 mill. **Due in 5 Yrs** $633.5 mill.
LT Debt $1590.2 mill. **LT Interest** $80.0 mill.
(LT interest earned: 5.0x)

Pension Assets-12/16 $304.5 mill.
Oblig. $350.4 mill.
Pfd Stock None

Common Stock 82,953,572 shs.
as of 4/28/17

MARKET CAP: $5.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.0	-2.4	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1407	1357	1360
Peak Load, Summer (Mw)	1095	1088	1096
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.7	+.8
Fixed Charge Cov. (%)	363	428	446

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	2.0%	2.5%	*4.0%*
"Cash Flow"	4.5%	4.0%	*6.0%*
Earnings	4.0%	6.0%	*6.5%*
Dividends	2.5%	2.5%	*4.5%*
Book Value	3.0%	3.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.)F Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	796.8	542.5	595.6	676.8	2611.7
2015	706.2	551.0	573.5	604.0	2434.7
2016	584.8	533.7	631.0	699.0	2448.3
2017	624.5	*550*	*645*	*700.5*	*2520*
2018	*650*	*575*	*675*	*725*	*2625*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	.62	.14	.57	.69	2.02
2015	.69	.43	.48	.79	2.39
2016	.58	.39	.74	.84	2.55
2017	.67	*.41*	*.74*	*.83*	*2.65*
2018	*.70*	*.45*	*.77*	*.88*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.355	.355	.355	.360	1.43
2014	.360	.360	.360	.380	1.46
2015	.380	.380	.380	.400	1.54
2016	.400	.400	.400	.420	1.62
2017	.420	.420			

BUSINESS: Vectren is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base exceeding 1.1 million. 2016 Electricity revenues: residential, 37%; commercial, 27%; industrial, 34%; other, 2%. 2016 Gas revenues: residential, 67%; commercial, 23%; other, 10%. Nonutility operations include Infrastructure Services and Energy Services. Est'd plant age: electric, 10 years. '16 depreciation rate: 4.0%. Has about 5,800 employees. Chairman, President, & CEO: Carl Chapman. Incorporated: Indiana. Address: One Vectren Square, Evansville, Indiana 47708. Telephone: 812-491-4000. Internet: www.vectren.com.

Shares of Vectren have continued to move higher over the past three months. The company reported good results for the March quarter. The top line increased roughly 7%, year to year. Share net advanced about 16%, to $0.67. Results at the Utility Group benefited from ongoing investment in gas infrastructure programs in both Indiana and Ohio, though very warm weather during the period was a partial offset. Elsewhere, the Infrastructure Services' Distribution business performed well. This operation gained from strong demand for utility distribution infrastructure replacement and an extended construction period owing to relatively mild weather. Looking forward, earnings growth may well prove more difficult to come by for the remainder of the year.

We anticipate solid performance from 2018 onward. The Gas Utility Services business ought to further benefit from infrastructure investment programs. Thanks to rate design, customer margin is largely unaffected by weather. Gains may be more modest at the Electric Utility Services segment. Results here are not protected by weather-normalizing mechanisms. Overall, though, we expect good performance on the utility side. Meanwhile, the Infrastructure Services Distribution business should continue to prosper as gas utilities make significant investments in their systems. The Infrastructure Services Transmission operation has been impacted by greater competition, though we expect this line will experience healthy demand down the road due to the need to replace aging infrastructure.

Subscribers may prefer to remain on the sidelines, for now. This equity does not stand out for year-ahead performance. Looking further out, this issue lacks long-term appreciation potential, as the shares presently trade slightly above our projected range, following a run-up in the stock price that began early in 2016. Prospects for moderate growth appear to be reflected in the recent quotation.

A selloff some time in the future may offer conservative accounts a better entry point. Vectren earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. Volatility is below average, too.

Michael Napoli, CFA *June 16, 2017*

(A) Diluted EPS. Excl. nonrecur. gain (loss): '09, 15¢. Next egs report due early August. (B) Div'ds historically paid in early March, June, September, and December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '16, $7.27/sh. (D) In millions. (E) Electric rate base determination: fair value. Rates allowed on elect. common equity range from 10.15% to 10.4%. Regulatory Climate: Above Average. (F) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	75

AVANGRID, INC. NYSE-AGR

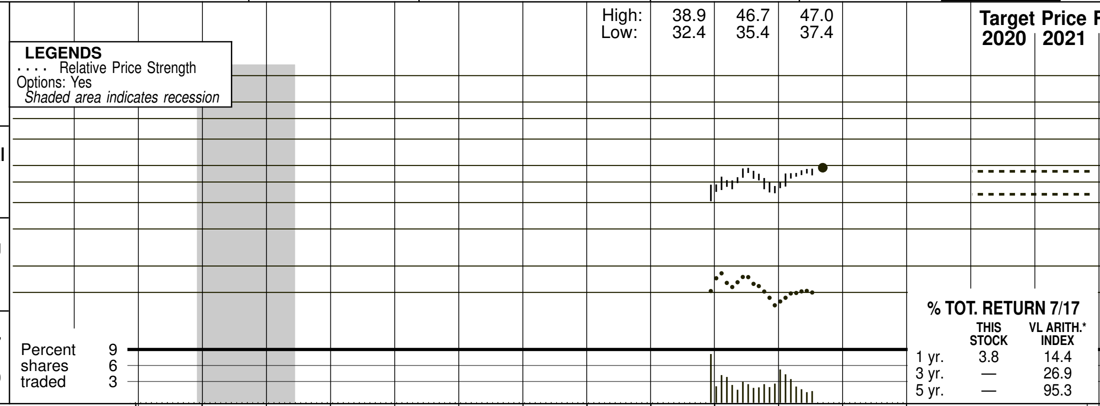
RECENT PRICE	46.93	P/E RATIO	21.0 (Trailing: 21.5 / Median: NMF)	RELATIVE P/E RATIO	1.10	DIV'D YLD	3.7%	VALUE LINE

TIMELINESS 1 New 8/18/17
SAFETY 2 Raised 2/17/17
TECHNICAL 5 New 8/18/17
BETA NMF (1.00 = Market)

	2015	2016	2017
High:	38.9	46.7	47.0
Low:	32.4	35.4	37.4

Target Price Range 2020 | 2021 | 2022

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(-5%)	3%
Low	35	(-25%)	-2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	1	3	1	0	2	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	110	106	121
to Sell	86	109	80
Hld's(000)	38903	39830	43670

% TOT. RETURN 7/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.8	14.4
3 yr.	—	26.9
5 yr.	—	95.3

AVANGRID, Inc. was formed through a merger between Iberdrola USA, Inc. and UIL Holdings Corporation in December of 2015. Iberdrola S.A., a worldwide leader in the energy industry, owns 81.5% of AVANGRID. The predecessor company was founded in 1852 and is headquartered in New Gloucester, Maine. It was incorportated in 1997 in New York under the name NGE Resources, Inc. AVANGRID began trading on the NYSE on December 17, 2015.

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
--	--	--	--	--	--	--	--	14.14	19.48	19.90	20.70	Revenues per sh	23.25
--	--	--	--	--	--	--	--	3.44	4.74	4.95	5.20	"Cash Flow" per sh	6.00
--	--	--	--	--	--	--	--	1.05	1.98	2.15	2.30	Earnings per sh A	2.75
--	--	--	--	--	--	--	--	--	1.73	1.73	1.76	Div'd Decl'd per sh B ■	1.90
--	--	--	--	--	--	--	--	3.50	5.52	6.80	6.45	Cap'l Spending per sh	5.75
--	--	--	--	--	--	--	--	48.74	48.90	49.35	49.90	Book Value per sh C	52.25
--	--	--	--	--	--	--	--	308.86	308.99	309.00	309.00	Common Shs Outst'g D	309.00
--	--	--	--	--	--	--	--	33.5	20.5	Bold figures are		Avg Ann'l P/E Ratio	14.5
--	--	--	--	--	--	--	--	1.69	1.08	Value Line		Relative P/E Ratio	.90
--	--	--	--	--	--	--	--	--	4.3%	estimates		Avg Ann'l Div'd Yield	4.7%
--	--	--	--	--	--	--	4594.0	4367.0	6018.0	6150	6400	Revenues ($mill)	7150
--	--	--	--	--	--	--	424.0	267.0	611.0	675	715	Net Profit ($mill)	845
--	--	--	--	--	--	--	39.9%	11.3%	37.4%	35.0%	35.0%	Income Tax Rate	35.0%
--	--	--	--	--	--	--	6.8%	12.7%	7.5%	7.0%	7.0%	AFUDC % to Net Profit	6.0%
--	--	--	--	--	--	--	16.8%	23.1%	23.0%	24.0%	24.5%	Long-Term Debt Ratio	24.0%
--	--	--	--	--	--	--	83.2%	76.9%	77.0%	76.0%	75.5%	Common Equity Ratio	76.0%
--	--	--	--	--	--	--	14956	19583	19619	20075	20400	Total Capital ($mill)	21200
--	--	--	--	--	--	--	17099	20711	21548	22800	23900	Net Plant ($mill)	26300
--	--	--	--	--	--	--	3.7%	2.1%	3.8%	4.0%	4.0%	Return on Total Cap'l	4.5%
--	--	--	--	--	--	--	3.4%	1.8%	4.0%	4.5%	4.5%	Return on Shr. Equity	5.0%
--	--	--	--	--	--	--	3.4%	1.8%	4.0%	4.5%	4.5%	Return on Com Equity E	5.0%
--	--	--	--	--	--	--	3.4%	1.8%	1.4%	1.0%	1.0%	Retained to Com Eq	1.5%
--	--	--	--	--	--	--	--	--	66%	79%	76%	All Div'ds to Net Prof	69%

CAPITAL STRUCTURE as of 6/30/17
Total Debt $5399 mill. **Due in 5 Yrs** $2237 mill.
LT Debt $4773 mill. **LT Interest** $233 mill.
Incl. $104 mill. capitalized leases.
(LT interest earned: 4.7x)
Leases, Uncapitalized Annual rentals $106 mill.

Pension Assets-12/16 $2672 mill. **Oblig** $3448 mill.
Pfd Stock None

Common Stock 309,005,272 shs.
as of 7/31/17
MARKET CAP: $15 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	+.5
Fixed Charge Cov. (%)	347	183	415

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	--	--	NMF
"Cash Flow"	--	--	NMF
Earnings	--	--	NMF
Dividends	--	--	NMF
Book Value	--	--	NMF

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1556	938	982	1118	4594.0
2015	1227	939	1048	1153	4367.0
2016	1670	1439	1418	1491	6018.0
2017	1758	1331	1461	1600	6150
2018	1850	1400	1500	1650	6400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	--	--	--	--	--
2015	.42	.04	.22	.37	1.05
2016	.63	.33	.35	.67	1.98
2017	.77	.39	.34	.65	2.15
2018	.85	.40	.35	.70	2.30

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	--	--	--	--	--
2014	--	--	--	--	--
2015	--	--	--	--	--
2016	--	.432	.432	.432	1.30
2017	.432	.432	.432		

BUSINESS: AVANGRID, Inc., formerly Iberdrola USA, Inc., is a diversified energy and utility company that serves 2.2 million electric customers in New York, Connecticut, and Maine and 1 million gas customers in New York, Connecticut, Massachusetts and Maine. Has a nonregulated generating subsidiary focused on wind power, with 6.5 gigawatts of capacity. Revenue breakdown by customer class not available. Generating sources not available. Fuel costs: 21% of revenues. '16 depreciation rate: 3.0%. Iberdrola owns 81.5% of stock. Has 6,800 employees. Chairman: José Ignacio Sanchez Galan. CEO: James P. Torgerson. Incorporated: New York. Address: 157 Church Street, New Haven, Connecticut 06506. Telephone: 207-688-6363. Internet: www.avangrid.com.

We estimate that AVANGRID will post solid profit growth in 2017 and 2018. The company's regulated utility business is benefiting from rate relief and effective expense management. In Connecticut, United Illuminating received a tariff hike at the start of this year, and will get additional increases in 2018 and 2019. In New York, the company's two utilities received electric and gas increases on May 1st of 2016 and 2017, and additional rate boosts will occur on May 1, 2018. AVANGRID's renewables subsidiary is benefiting from the addition of wind and solar projects. In 2017, the company expects to add some 600 megawatts of renewable capacity.

Southern Connecticut Gas filed a rate case. It requested a total increase of $19 million over a three-year period, based on a return of 9.95% on a common-equity ratio of 52%. The utility is also asking for regulatory mechanisms to recover the cost of gas main replacement automatically (without filing a general rate case) and decouple revenues and volume. AVANGRID's other utility in the state, Connecticut Natural Gas, already has these mechanisms. New rates should take effect at the start of 2018.

It appears as if a dividend increase will occur sooner than we had expected. Due to AVANGRID's high payout ratio, we had forecast no hike in the disbursement before the end of the decade. However, management has stated a commitment to increase the dividend by 2018. We now look for a modest boost next year.

AVANGRID is still deciding what to do about its gas storage business. This operation is a drag on earnings. It lost $0.14 a share in 2016, and management estimates the deficit will be $0.08-$0.12 a share this year. The company is excluding this from its 2017 share-net guidance of $2.10-$2.35 because it is noncore, but we are *including* it in our earnings presentation. AVANGRID expects to make a decision by yearend.

This timely stock has a dividend yield that is about half a percentage point above the utility average. With the recent price above our 2020-2022 Target Price Range, total return potential is negligible. We think the quotation reflects some takeover speculation.

Paul E. Debbas, CFA *August 18, 2017*

(A) Diluted EPS. Excl. nonrecurring gain: '16, 6¢. Next earnings report due mid-Oct. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '16: $6.8 bill., $21.86/sh. (D) In millions. (E) Rate base: net original cost. Rate allowed on com. eq. in NY in '16: 9.0%; in CT in '17: 9.1% elec.; in CT in '16: 9.36% gas; in ME in '14: 9.45%; earned on avg. common eq., '16: 4.1%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	NMF
Price Growth Persistence	NMF
Earnings Predictability	NMF

DOMINION ENERGY NYSE-D

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
77.96	22.7	(Trailing: 22.5 / Median: 19.0)	1.19	4.1%	VALUE LINE

TIMELINESS 4 Lowered 8/11/17
SAFETY 2 Raised 9/11/98
TECHNICAL 3 Lowered 8/18/17
BETA .65 (1.00 = Market)

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+35%)	*11%*
Low	75	(-5%)	*4%*

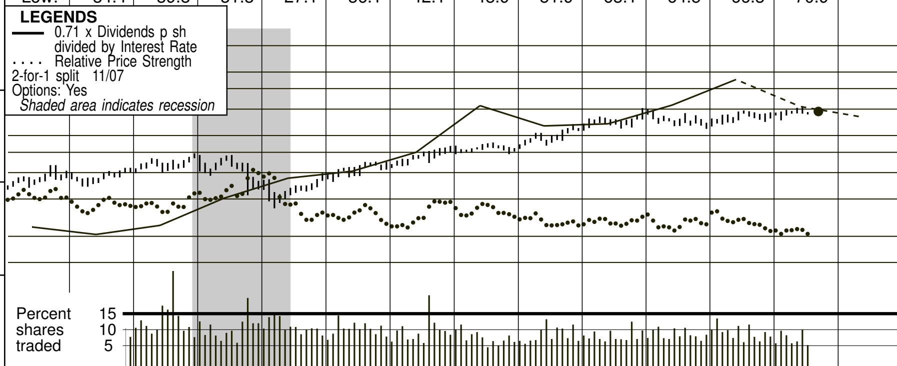
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	1	8	1	0	6	1
to Sell	0	0	0	1	0	1	0	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	423	449	434
to Sell	377	400	414
Hld's(000)	406322	407763	465004

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	42.2	49.4	48.5	39.8	45.1	53.6	55.6	68.0	80.9	79.9	79.0	81.6
Low:	34.4	39.8	31.3	27.1	36.1	42.1	48.9	51.9	63.1	64.5	66.3	70.9



Target Price Range 2020 | 2021 | 2022
160 / 120 / 100 / 80 / 60 / 50 / 40 / 30 / 20 / 15

% TOT. RETURN 7/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.8	14.4
3 yr.	27.5	26.9
5 yr.	71.5	95.3

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
19.94	16.58	18.57	20.54	25.96	23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	*19.35*	*19.90*	Revenues per sh	*22.50*
3.92	4.45	3.97	4.18	3.70	4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.33	*6.75*	*7.45*	"Cash Flow" per sh	*9.00*
1.49	2.41	1.96	2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	*3.40*	*3.80*	Earnings per sh A	*4.50*
1.29	1.29	1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	*3.02*	*3.30*	Div'd Decl'd per sh B ■	*4.20*
2.31	2.17	5.20	3.88	4.83	5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.69	*8.95*	*7.80*	Cap'l Spending per sh	*8.75*
15.81	16.57	16.20	16.79	14.96	18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.26	*25.10*	*25.65*	Book Value per sh C	*24.25*
529.40	616.20	650.40	680.40	695.00	698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.80	*643.50*	*643.50*	Common Shs Outst'g D	*615.00*
20.9	12.0	15.2	15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
1.07	.66	.87	.80	1.33	.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.13	*Value Line*		Relative P/E Ratio	*1.25*
4.1%	4.4%	4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $37038 mill. **Due in 5 Yrs** $15096 mill.
LT Debt $30155 mill. **LT Interest** $1197 mill.
(LT interest earned: 3.2x)

Leases, Uncapitalized Annual rentals $72 mill.

Pension Assets-12/16 $7016 mill. **Oblig** $8132 mill.

Pfd Stock None

Common Stock 642,585,953 shs. as of 7/14/17
MARKET CAP: $50 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
15674	16290	15131	15197	14379	13093	13120	12436	11683	11737	*12450*	*12800*	Revenues ($mill)	*13850*
1414.0	1781.0	1585.0	1724.0	1603.0	1594.0	1806.0	1793.0	1899.0	2123.0	*2255*	*2570*	Net Profit ($mill)	*2975*
33.4%	37.1%	33.2%	38.6%	34.6%	36.2%	33.0%	28.1%	32.0%	22.8%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
7.3%	4.9%	4.8%	5.9%	5.3%	5.7%	3.7%	4.5%	5.3%	7.5%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
57.8%	59.1%	57.5%	56.3%	59.8%	60.9%	61.9%	65.4%	65.1%	67.4%	*67.0%*	*65.5%*	Long-Term Debt Ratio	*70.5%*
41.1%	39.8%	41.5%	42.8%	39.3%	38.2%	37.3%	34.6%	34.9%	32.6%	*33.0%*	*34.5%*	Common Equity Ratio	*29.5%*
22898	25290	26923	28012	29097	27676	31229	33360	36280	44836	*48825*	*48125*	Total Capital ($mill)	*50800*
21352	23274	25592	26713	29670	30773	32628	36270	41554	49964	*53550*	*56275*	Net Plant ($mill)	*64300*
8.0%	8.7%	7.5%	7.7%	7.0%	7.5%	7.3%	6.6%	6.5%	6.0%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.5%*
14.6%	17.2%	13.9%	14.1%	13.7%	14.7%	15.2%	15.5%	15.0%	14.5%	*13.5%*	*15.0%*	Return on Shr. Equity	*19.0%*
14.9%	17.5%	14.0%	14.2%	13.9%	14.9%	15.4%	15.4%	15.0%	14.5%	*13.5%*	*15.0%*	Return on Com Equity E	*19.0%*
5.0%	8.4%	4.7%	5.3%	4.0%	3.5%	4.2%	3.3%	2.9%	2.7%	*1.5%*	*2.0%*	Retained to Com Eq	*1.5%*
67%	52%	67%	63%	71%	77%	73%	79%	81%	81%	*85%*	*83%*	All Div'ds to Net Prof	*88%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+1.6	+.7	NA
Avg. Indust. Use (MWH)	13847	13433	NA
Avg. Indust. Revs. per KWH (¢)	6.12	6.17	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+.9	NA
Fixed Charge Cov. (%)	266	352	310

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-1.5%	-5.0%	*2.0%*
"Cash Flow"	3.5%	4.0%	*7.0%*
Earnings	5.0%	3.0%	*5.5%*
Dividends	7.0%	7.0%	*8.5%*
Book Value	2.5%	1.5%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3630	2813	3050	2943	12436
2015	3409	2747	2971	2556	11683
2016	2921	2598	3132	3086	11737
2017	3384	2813	*3150*	*3103*	*12450*
2018	*3500*	*2900*	*3250*	*3150*	*12800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.03	.60	.95	.47	3.05
2015	.91	.70	1.00	.59	3.20
2016	.88	.73	1.10	.73	3.44
2017	1.01	.62	*1.02*	*.75*	*3.40*
2018	*1.05*	*.80*	*1.10*	*.85*	*3.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.562	.562	.563	.563	2.25
2014	.60	.60	.60	.60	2.40
2015	.647	.647	.648	.648	2.59
2016	.70	.70	.70	.70	2.80
2017	.755	.755			

BUSINESS: Dominion Energy, Inc. (formerly Dominion Resources, Inc.) is a holding company for Virginia Power & North Carolina Power, which serve 2.6 mill. customers in VA & northeastern NC. Serves 2.3 mill. gas customers in OH, WV, & UT. Nonutility ops. incl. independent power production. Owns 70.9% of Dominion Midstream Partners. Acq'd Questar 9/16. Elec. rev. breakdown: residential, 46%; commercial, 32%; industrial, 7%; other, 15%. Generating sources: nuclear, 31%; gas, 31%; coal, 24%; other, 6%; purch., 8%. Fuel costs: 25% of revs. '16 reported depr. rates: 2.3%-4.1%. Has 16,200 employees. Chairman, Pres. & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dom.com.

We think Dominion Energy's share profits will decline modestly in 2017. (The company changed its name from Dominion Resources; the stock's ticker symbol remains D.) Unfavorable weather conditions hurt earnings by $0.10 a share in the first six months of 2017. The company is incurring integration expenses associated with its acquisition of Questar last September. Tax credits for solar investments are declining; this will hurt the year-to-year comparison by $0.20 a share. The Millstone nonregulated nuclear plant in Connecticut is receiving lower prices for the power it is producing, and will have an additional refueling outage. Average shares outstanding are rising as Dominion issues common equity. Our earnings estimate is at the low end of management's guidance of $3.40-$3.90 a share.

The company expects to increase earnings by at least 10% next year. The biggest factor is the conversion of the Cove Point liquefied natural gas terminal into an export facility. This project is on track for completion in late 2017, and will add an estimated $0.40-$0.45 a share to the bottom line in 2018. We forecast a 12% increase, to $3.80 a share. We are not assuming that Connecticut will pass legislation that would provide subsidies for Millstone, but such a move would be another positive factor for Dominion.

Some significant projects are in various stages of development. Virginia Power is building a 1,588-megawatt gas-fired plant. This is expected to achieve commercial operation in late 2018 at a cost of $1.3 billion. Dominion is a partner in a natural gas pipeline that is expected to be completed in late 2019. The capital spending on this project is expected at $1.5 billion. The company plans to spend $800 million a year on electric transmission for at least the next decade. Its long-term goal for profit growth is 6%-8% annually.

The untimely stock has an above-average dividend yield, even by utility standards. Stockholders can look forward to strong dividend growth, thanks to the distributions Dominion receives from its interest in Dominion Midstream Partners, a gas master limited partnership. Total return potential over the 3- to 5-year period is superior to that of most utility equities.

Paul E. Debbas, CFA *August 18, 2017*

(A) Dil. egs. Excl. nonrec. gains (losses): '01, (42¢); '03, ($1.46); '04, (22¢); '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); losses from disc. ops.: '06, 26¢; '07, 1¢; '10, 26¢; '12, 4¢; '13, 16¢. '14 & '15 EPS don't add due to rounding. Next egs. due early Nov. (B) Div'ds histor. paid in mid-Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '16: $15.12/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earn. on avg. com. eq., '16: 15.8%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	90

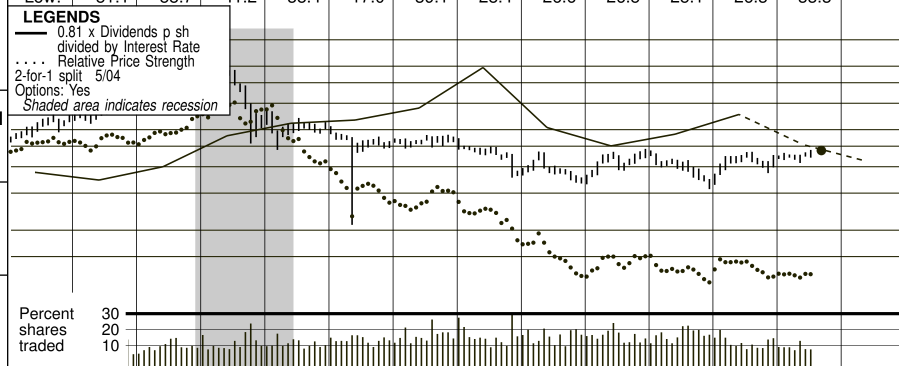
EXELON CORP. NYSE-EXC

RECENT PRICE	38.21	P/E RATIO	15.2 (Trailing: 16.3 Median: 15.0)	RELATIVE P/E RATIO	0.80	DIV'D YLD	3.5%	VALUE LINE

TIMELINESS 4 Lowered 6/16/17
SAFETY 3 Lowered 11/23/12
TECHNICAL 3 Raised 7/7/17
BETA .70 (1.00 = Market)

High:	63.6	86.8	92.1	59.0	49.9	45.4	43.7	37.8	38.9	38.3	37.7	38.8
Low:	51.1	58.7	41.2	38.4	17.0	39.1	28.4	26.6	26.5	25.1	26.3	33.3

LEGENDS
—— 0.81 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/04
Options: Yes
Shaded area indicates recession



Target Price Range

2020	2021	2022

128, 96, 80, 64, 48, 40, 32, 24, 16, 12

Percent shares traded 30 20 10

% TOT. RETURN 7/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.9	14.4
3 yr.	38.3	26.9
5 yr.	21.1	95.3

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	13%
Low	35	(-10%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	1	0
Options	0	1	1	0	11	0	0	0	1
to Sell	0	0	1	0	1	0	0	0	2

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	337	383	354
to Sell	336	333	364
Hld's(000)	679803	705876	781249

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
23.58	23.13	24.09	21.85	23.05	23.37	28.62	28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	*34.75*	*35.75*	Revenues per sh	*38.25*
5.06	5.03	5.06	5.68	6.19	6.71	7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.01	*8.00*	*8.30*	"Cash Flow" per sh	*9.25*
2.20	2.40	2.44	2.75	3.21	3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	1.80	*2.60*	*2.70*	Earnings per sh A	*3.25*
.91	.88	.96	1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	*1.31*	*1.34*	Div'd Decl'd per sh B ■	*1.70*
3.18	3.33	2.98	2.89	3.25	3.61	4.05	4.74	4.96	5.03	6.09	6.77	6.29	7.07	8.29	9.26	*8.60*	*8.30*	Cap'l Spending per sh	*8.25*
12.82	11.97	12.95	14.19	13.69	14.89	15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	*28.85*	*30.20*	Book Value per sh C	*35.50*
642.01	646.63	656.37	664.19	666.37	669.86	660.88	658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	924.04	*958.00*	*961.00*	Common Shs Outst'g D	*970.00*
13.2	10.5	11.8	13.0	15.4	16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.68	.57	.67	.69	.82	.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.99	*Value Line*		Relative P/E Ratio	*.90*
3.1%	3.5%	3.4%	3.5%	3.2%	2.8%	2.5%	2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*
						18916	18859	17318	18644	18924	23489	24888	27429	29447	31360	*33300*	*34350*	Revenues ($mill)	*37500*
						2730.0	2721.0	2844.0	2567.0	2499.0	1579.0	1999.0	1826.0	2282.0	1677.0	*2455*	*2620*	Net Profit ($mill)	*3155*
						34.6%	32.6%	38.8%	39.2%	36.8%	32.4%	36.5%	27.2%	32.2%	38.5%	*33.0%*	*33.0%*	Income Tax Rate	*33.0%*
						1.8%	1.3%	2.3%	2.1%	3.0%	5.8%	4.5%	5.5%	5.4%	12.3%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
						53.9%	53.1%	47.2%	46.8%	45.7%	45.8%	44.4%	46.7%	48.3%	55.5%	*55.0%*	*54.0%*	Long-Term Debt Ratio	*53.0%*
						45.7%	46.6%	52.4%	52.9%	54.0%	53.5%	55.2%	52.8%	51.3%	44.5%	*45.0%*	*46.0%*	Common Equity Ratio	*47.0%*
						22189	23726	24112	25651	26661	40057	41196	42811	50272	58053	*61550*	*63375*	Total Capital ($mill)	*71300*
						24153	25813	27341	29941	32570	45186	47330	52087	57439	71555	*75075*	*78225*	Net Plant ($mill)	*86600*
						14.1%	13.1%	13.3%	11.4%	10.6%	5.1%	5.9%	5.3%	5.5%	4.1%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
						26.7%	24.4%	22.3%	18.8%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
						26.9%	24.6%	22.5%	18.9%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
						15.3%	12.5%	11.5%	8.7%	7.7%	NMF	3.2%	3.3%	4.5%	1.9%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
						43%	49%	49%	54%	56%	109%	63%	59%	49%	70%	*50%*	*49%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 6/30/17
Total Debt $36332 mill. **Due in 5 Yrs** $12720 mill.
LT Debt $30956 mill. **LT Interest** $1316 mill.
Includes $641 mill. nonrecourse transition bonds.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $183 mill.

Pension Assets-12/16 $16791 mill. **Oblig** $21060 mill.

Pfd Stock None

Common Stock 960,087,898 shs.

MARKET CAP: $37 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-.7	-1.0	+25.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Nuclear Capacity Factor (%)	94.3	NA	NA
% Change Customers (yr-end)	+.6	+1.1	+33.7
Fixed Charge Cov. (%)	263	367	238

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	3.5%	3.5%	*3.0%*
"Cash Flow"	1.0%	-3.0%	*5.5%*
Earnings	-4.0%	-11.5%	*7.0%*
Dividends	-2.0%	-10.0%	*5.5%*
Book Value	7.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	7237	6024	6912	7256	27429
2015	8830	6514	7401	6702	29447
2016	7573	6910	9002	7875	31360
2017	8757	7623	*9020*	*7900*	*33300*
2018	*9000*	*7900*	*9250*	*8200*	*34350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.10	.68	.96	.36	2.10
2015	.80	.74	.69	.33	2.54
2016	.26	.45	.76	.32	1.80
2017	.83	.44	*.85*	*.48*	*2.60*
2018	*.75*	*.55*	*.90*	*.50*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.525	.31	.31	.31	1.46
2014	.31	.31	.31	.31	1.24
2015	.31	.31	.31	.31	1.24
2016	.31	.318	.318	.318	1.26
2017	.3275	.3275			

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, PECO Energy, Baltimore Gas and Electric, Pepco, Delmarva Power, & Atlantic City Electric. Has 8.6 mill. elec., 1.3 mill. gas customers. Has nonregulated generating & energy-marketing ops. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: res'l, 63%; small comm'l & ind'l, 23%; large comm'l & ind'l, 13%; other, 1%. Generating sources: nuclear, 68%; other, 8%; purch., 24%. Fuel costs: 40% of revs. '16 depr. rates: 2.7%-5.9% elec., 2.2% gas. Has 34,400 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Some of Exelon's utilities have received rate increases this year, while others have rate cases pending. The utilities that Exelon owns through the Pepco Holdings acquisition last year are not earning adequate returns on equity. In the first quarter, Delmarva Power received a $38.3 million electric rate hike in Maryland, based on a 9.6% ROE. In the second period, this utility was granted electric and gas tariff increases totaling $36.4 million, based on a 9.7% ROE. Last month, Pepco was granted a $36.9 million increase in Washington, DC, based on a 9.5% ROE. The second cycle of rate cases has begun, with Pepco seeking a $68.6 million rate hike in Maryland. An order is expected in October. Atlantic City Electric is asking the New Jersey regulators for a $72.6 million raise. A ruling is expected in the first quarter of 2018. Finally, Delmarva requested an electric increase of $27.0 million in Maryland. A decision is due in mid-February. All three of these filings are based on a 10.1% ROE.

Earnings should advance sharply this year and modestly in 2018. This year, costs associated with the Pepco deal will likely be below the 2016 level of $0.59 a share. Rate relief should be a positive factor each year. Note that ongoing and unpredictable accounting items, such as mark-to-market gains or charges and changes in the value of the nuclear decommissioning trust, can affect earnings.

Exelon's nonregulated business is operating in a difficult environment. Low natural gas prices, subsidized renewable energy, and weak demand for power are hurting this operation. In May, two nuclear plants (Quad Cities in Illinois and Three Mile Island in Pennsylvania) were unsuccessful bidders in the annual auction in their power pool. There are programs in place in Illinois and New York to subsidize nuclear energy to recognize their environmental benefits, but this did not help Quad Cities. Exelon plans to shut Three Mile Island (which is unprofitable, even on a cash flow basis) in 2019 unless a similar program is initiated in Pennsylvania.

This untimely stock has a dividend yield that is about average for a utility. Total return potential to 2020-2022 is above average for this industry.

Paul E. Debbas, CFA *August 18, 2017*

(A) Dil. egs. Excl. nonrec. gain (losses): '03, ($1.06); '05, ($1.85); '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢; '16, (58¢); '17, (60¢). '14-'16 EPS don't add due to rounding or chg. in shs. Next egs. report due early Nov. **(B)** Div'ds paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. def'd chgs. In '16: $18.58/sh. **(D)** In mill., adj. for split. **(E)** Rate all'd on com. eq. in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%; earn. on avg. com. eq., '16: 6.4%. Reg. Clim.: PA, NJ Avg.; IL, MD, Below Avg.

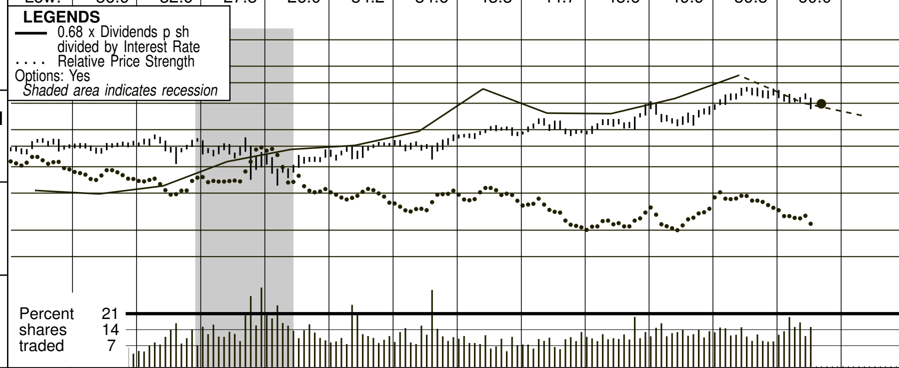
Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	10
Earnings Predictability	55

SCANA CORP. NYSE-SCG

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
63.65	14.9	(Trailing: 15.0 Median: 14.0)	0.78	4.0%	VALUE LINE

TIMELINESS 2 Raised 8/18/17
SAFETY 2 Lowered 9/10/99
TECHNICAL 3 Lowered 8/11/17
BETA .65 (1.00 = Market)

High:	42.4	45.5	44.1	38.6	42.0	45.5	50.3	54.4	63.4	65.6	76.4	74.1
Low:	36.9	32.9	27.8	26.0	34.2	34.6	43.3	44.7	45.6	49.9	59.5	60.0



Target Price Range

2020	2021	2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+35%)	11%
Low	60	(-5%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	2	0	0	3	0	0	3	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2016	4Q2016	1Q2017
to Buy	201	240	231
to Sell	215	220	251
Hld's(000)	92291	93634	111512

% TOT. RETURN 7/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.1	14.4
3 yr.	41.3	26.9
5 yr.	59.0	95.3

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
32.95	26.65	30.85	34.53	41.66	39.11	39.61	45.16	34.35	36.10	33.95	31.63	31.88	34.70	30.65	29.58	29.40	31.25	Revenues per sh	38.00
4.55	4.56	4.95	5.28	7.43	5.68	5.73	5.86	5.63	5.91	6.01	6.30	6.53	6.91	6.70	7.28	7.45	7.95	"Cash Flow" per sh	9.75
2.15	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.98	2.97	3.15	3.39	3.79	3.81	4.16	4.15	4.25	Earnings per sh A	5.00
1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.94	1.98	2.03	2.10	2.18	2.30	2.45	2.60	Div'd Decl'd per sh B ■ †	2.90
4.99	6.41	6.94	4.86	3.38	4.52	6.21	7.68	7.41	6.87	6.81	8.16	7.84	7.65	8.07	11.05	11.70	6.45	Cap'l Spending per sh	7.25
20.95	19.64	20.82	21.78	23.35	24.39	25.37	25.85	27.63	29.05	29.94	31.47	33.08	34.95	38.09	40.06	41.70	42.60	Book Value per sh C	46.25
104.73	110.83	110.74	112.52	114.67	116.67	116.67	117.78	123.34	127.45	129.88	132.01	141.00	142.70	142.90	142.90	142.90	137.50	Common Shs Outst'g D	125.00
12.6	12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	12.9	13.7	14.8	14.4	13.7	14.7	16.8	Bold figures are		Avg Ann'l P/E Ratio	14.5
.65	.67	.74	.72	.77	.83	.80	.76	.77	.82	.86	.94	.81	.72	.74	.89	Value Line		Relative P/E Ratio	.90
4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	4.9%	4.8%	4.2%	4.2%	4.1%	3.9%	3.3%	estimates		Avg Ann'l Div'd Yield	4.0%

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
4621.0	5319.0	4237.0	4601.0	4409.0	4176.0	4495.0	4951.0	4380.0	4227.0	4200	4300	Revenues ($mill)	5000
327.0	353.0	357.0	376.0	387.0	420.0	471.0	538.0	544.0	595.0	600	600	Net Profit ($mill)	635
29.2%	35.4%	32.0%	29.8%	30.3%	30.2%	32.1%	31.6%	31.8%	31.3%	31.0%	31.5%	Income Tax Rate	33.0%
4.6%	8.5%	14.3%	8.0%	5.4%	7.6%	8.7%	9.1%	7.7%	8.1%	9.0%	4.0%	AFUDC % to Net Profit	3.0%
48.4%	58.0%	56.8%	52.9%	54.3%	54.4%	53.6%	52.6%	51.9%	53.1%	49.5%	53.5%	Long-Term Debt Ratio	54.0%
49.7%	40.5%	43.2%	47.1%	45.7%	45.6%	46.4%	47.4%	48.1%	46.9%	50.5%	46.5%	Common Equity Ratio	46.0%
5952.0	7519.0	7891.0	7854.0	8511.0	9103.0	10059	10518	11325	12198	11875	12575	Total Capital ($mill)	12600
7538.0	8305.0	9009.0	9662.0	10047	10896	11643	12232	13425	14324	15525	15925	Net Plant ($mill)	16900
7.3%	6.2%	6.1%	6.5%	6.2%	6.3%	6.2%	6.6%	6.2%	6.3%	6.5%	6.0%	Return on Total Cap'l	6.5%
10.6%	11.2%	10.5%	10.2%	10.0%	10.1%	10.1%	10.8%	10.0%	10.4%	10.0%	10.5%	Return on Shr. Equity	11.0%
10.8%	11.4%	10.2%	10.2%	10.0%	10.1%	10.1%	10.8%	10.0%	10.4%	10.0%	10.5%	Return on Com Equity E	11.0%
4.0%	4.4%	3.6%	3.8%	3.6%	3.9%	4.1%	4.9%	4.3%	4.7%	4.0%	4.0%	Retained to Com Eq	4.5%
64%	62%	66%	63%	64%	61%	60%	55%	57%	55%	59%	61%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 6/30/17
Total Debt $7760 mill. **Due in 5 Yrs** $2749 mill.
LT Debt $6455 mill. **LT Interest** $365 mill.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $31 mill.
Pension Assets-12/16 $793.6 mill.
Oblig $904.3 mill.
Pfd Stock None

Common Stock 142,916,917 shs.
as of 7/31/17
MARKET CAP: $9.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+4.7	-.9	+1.6
Avg. Indust. Use (MWH)	NA	NA	7991
Avg. Indust. Revs. per KWH (¢)	NA	NA	7.07
Capacity at Yearend (Mw)	5237	5234	5233
Peak Load, Summer (Mw)	4853	4970	4807
Annual Load Factor (%)	NA	NA	58.5
% Change Customers (yr-end)	+1.4	+1.5	+1.6
Fixed Charge Cov. (%)	307	323	319

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-2.0%	-2.0%	3.0%
"Cash Flow"	1.5%	3.5%	6.0%
Earnings	4.0%	6.0%	4.0%
Dividends	3.5%	3.0%	5.0%
Book Value	5.0%	5.5%	3.5%

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1590	1026	1121	1214	4951.0
2015	1389	967	1068	956	4380.0
2016	1172	905	1093	1057	4227.0
2017	1173	1001	1026	1000	4200
2018	1250	950	1050	1050	4300

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.37	.68	1.01	.73	3.79
2015	1.39	.69	1.04	.69	3.81
2016	1.23	.74	1.32	.87	4.16
2017	1.19	.85	1.25	.86	4.15
2018	1.30	.80	1.30	.85	4.25

QUARTERLY DIVIDENDS PAID B ■ †

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.495	.5075	.5075	.5075	2.02
2014	.5075	.525	.525	.525	2.08
2015	.525	.545	.545	.545	2.16
2016	.545	.575	.575	.575	2.27
2017	.575	.6125	.6125		

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 718,000 customers in central, southern, and southwestern South Carolina. Supplies gas service to 1.4 million customers in North Carolina, South Carolina, and Georgia. Electric revenue breakdown: residential, 46%; commercial, 33%; industrial, 17%; other, 4%. Generating sources: coal, 38%; gas & oil, 27%; nuclear, 23%; hydro & other, 4%; purchased, 8%. Fuel costs: 40% of revenues. '16 reported depreciation rate: 2.6%. Has 5,900 employees. Chairman, CEO & President: Kevin B. Marsh. Incorporated: South Carolina. Address: 100 SCANA Parkway, Cayce, South Carolina 29033. Telephone: 803-217-9000. Internet: www.scana.com.

SCANA's electric utility subsidiary has abandoned its nuclear construction project. South Carolina Electric & Gas had planned to build two units at the site of the Summer nuclear plant. However, the project had cost overruns and extensive delays. This led to the bankruptcy filing of the contractor, Westinghouse. The utility will receive a guarantee from Toshiba, Westinghouse's parent, but the $1.1 billion won't be nearly enough to complete the project. Considering that the co-owner did not want to proceed with construction, SCE&G had little choice but to abandon construction of both units.

SCE&G believes the project's costs are recoverable under the state's Base Load Review Act. The utility filed with the state commission to certify that abandonment was the best option. The commission's decision is due by February 1st. In November, SCE&G will file for revised rates, which should be effective in April. In order to mitigate the effect on customers' bills, the company proposes to amortize the cost of the project over a 60-year span and offset this with the proceeds from Toshiba. SCANA didn't take a write-down when it reported second-quarter results, but there is still regulatory uncertainty here. Note that 15 months of construction work in progress are not currently reflected in rates. In addition, the abandonment is politically unpopular.

The company's capital spending and financing plans have changed considerably. Instead of issuing common stock, SCANA expects to begin a buyback in 2018. The company tentatively plans to repurchase $1.2 billion through 2021. The reduction in shares outstanding should enable share net to approximate what it would have been had construction of the nuclear units continued. SCANA also plans to maintain its dividend policy, with a targeted payout ratio of 55%-65%.

Timely SCANA stock has performed poorly this year. Due to the problems surrounding the nuclear project, the price has declined more than 10% in what has been an excellent year for most utility issues. Although the dividend yield and 3- to 5-year total return potential are above the utility averages, investors need to be aware of the regulatory risks.

Paul E. Debbas, CFA *August 18, 2017*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢; '15, $1.41. Next earnings report due late Oct. (B) Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '16: $14.91/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in SC: 10.25% elec. in '13, 10.25% gas in '05; in NC: 9.7% in '16; earned on avg. com. eq., '16: 10.7%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	100

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 36, No. 6, June 1, 2017

Wolters Kluwer

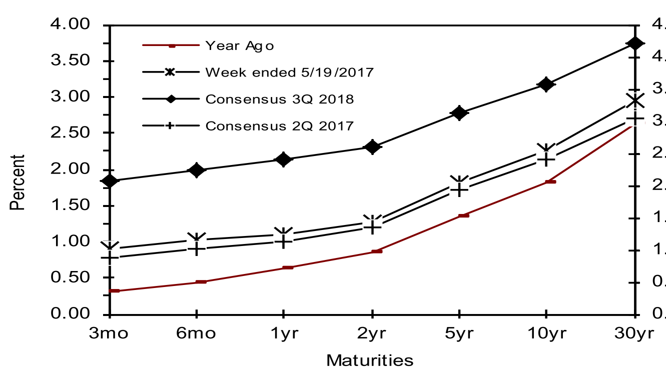
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	May 19	May 12	May 5	Apr. 28	Apr.	Mar.	Feb.	1Q 2017	2017	2017	2017	2018	2018	2018
Federal Funds Rate	0.91	0.91	0.88	0.91	0.90	0.76	0.66	0.69	1.0	1.2	1.4	1.5	1.7	1.9
Prime Rate	4.00	4.00	4.00	4.00	4.00	3.85	3.75	3.78	4.1	4.2	4.4	4.6	4.8	5.0
LIBOR, 3-mo.	1.18	1.18	1.18	1.17	1.16	1.13	1.04	1.06	1.2	1.4	1.6	1.8	2.0	2.2
Commercial Paper, 1-mo.	0.84	0.83	0.83	0.83	0.83	0.77	0.61	0.67	1.0	1.2	1.4	1.6	1.8	2.0
Treasury bill, 3-mo.	0.91	0.90	0.85	0.81	0.81	0.73	0.53	0.59	0.9	1.1	1.3	1.4	1.6	1.8
Treasury bill, 6-mo.	1.02	1.03	1.00	0.98	0.95	0.87	0.65	0.71	1.0	1.2	1.4	1.6	1.8	2.0
Treasury bill, 1 yr.	1.10	1.13	1.10	1.06	1.04	1.00	0.82	0.88	1.1	1.4	1.6	1.7	1.9	2.1
Treasury note, 2 yr.	1.28	1.34	1.30	1.27	1.24	1.30	1.20	1.24	1.3	1.6	1.8	1.9	2.1	2.3
Treasury note, 5 yr.	1.81	1.91	1.86	1.83	1.83	2.00	1.91	1.94	1.9	2.2	2.3	2.5	2.6	2.8
Treasury note, 10 yr.	2.27	2.39	2.33	2.31	2.30	2.47	2.43	2.44	2.4	2.6	2.8	2.9	3.1	3.2
Treasury note, 30 yr.	2.94	3.02	2.99	2.96	2.94	3.07	3.04	3.04	3.0	3.2	3.4	3.5	3.6	3.7
Corporate Aaa bond	3.94	4.05	4.03	4.00	4.00	4.13	4.10	4.10	4.0	4.3	4.5	4.6	4.7	4.9
Corporate Baa bond	4.52	4.64	4.62	4.60	4.60	4.71	4.68	4.68	4.7	5.0	5.2	5.3	5.5	5.6
State & Local bonds	3.49	3.55	3.56	3.54	3.55	3.72	3.72	3.71	3.7	3.9	4.1	4.2	4.3	4.4
Home mortgage rate	4.02	4.05	4.02	4.03	4.05	4.20	4.17	4.17	4.1	4.3	4.5	4.6	4.8	4.9

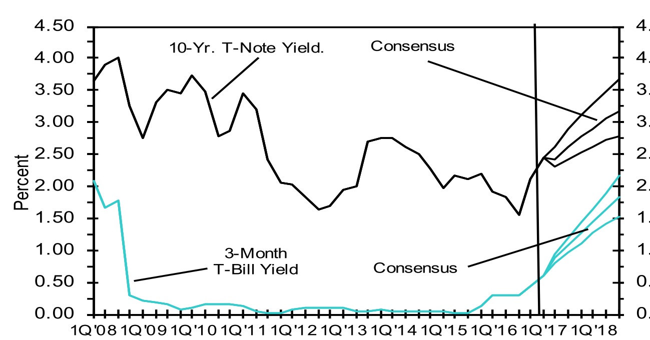
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2015	2015	2015	2016	2016	2016	2016	2017	2017	2017	2017	2018	2018	2018
Major Currency Index	89.9	91.8	93.1	93.3	89.6	90.3	93.7	94.4	94.0	94.1	94.5	94.6	94.4	94.2
Real GDP	2.6	2.0	0.9	0.8	1.4	3.5	2.1	1.2	3.1	2.4	2.4	2.4	2.5	2.4
GDP Price Index	2.3	1.3	0.8	0.5	2.3	1.4	2.1	2.2	1.5	2.0	2.1	2.2	2.1	2.2
Consumer Price Index	2.4	1.5	0.4	0.1	2.3	1.8	3.0	3.1	1.1	2.2	2.3	2.4	2.2	2.4

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data is sourced from Haver Analytics. Historical data for Fed's Major Currency Index is from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

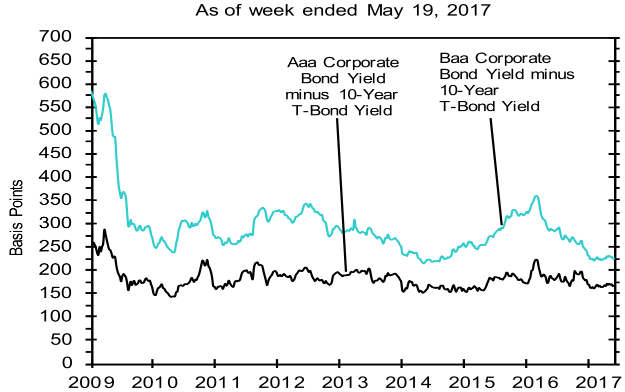
U.S. Treasury Yield Curve
Week ended May 19, 2017 and Year Ago vs. 2Q 2017 and 3Q 2018 Consensus Forecasts



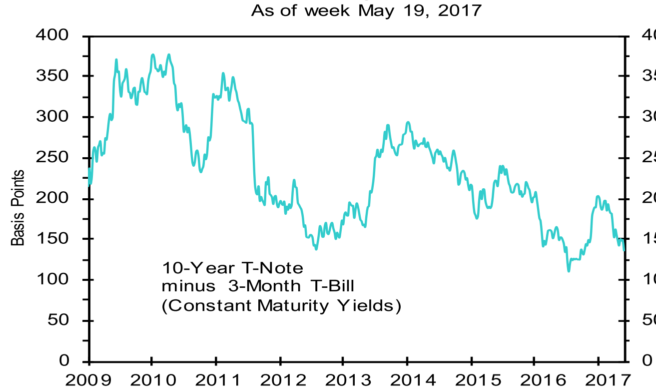
U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average)



Corporate Bond Spreads
As of week ended May 19, 2017



U.S. Treasury Yield Curve
As of week May 19, 2017



Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2019 through 2023 and averages for the five-year periods 2019-2023 and 2024-2028. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		-----------Average For The Year------------					Five-Year Averages	
Interest Rates		**2019**	**2020**	**2021**	**2022**	**2023**	**2019-2023**	**2024-2028**
1. Federal Funds Rate	**CONSENSUS**	**2.6**	**2.9**	**2.9**	**2.9**	**2.9**	**2.8**	**3.0**
	Top 10 Average	3.1	3.5	3.4	3.5	3.5	3.4	3.5
	Bottom 10 Average	2.0	2.3	2.3	2.3	2.4	2.3	2.4
2. Prime Rate	**CONSENSUS**	**5.6**	**5.9**	**5.9**	**5.9**	**5.9**	**5.8**	**6.0**
	Top 10 Average	6.1	6.5	6.5	6.5	6.5	6.4	6.5
	Bottom 10 Average	5.0	5.3	5.3	5.2	5.3	5.2	5.4
3. LIBOR, 3-Mo.	**CONSENSUS**	**2.9**	**3.1**	**3.2**	**3.1**	**3.2**	**3.1**	**3.2**
	Top 10 Average	3.4	3.7	3.7	3.7	3.8	3.7	3.8
	Bottom 10 Average	2.4	2.6	2.6	2.5	2.6	2.5	2.6
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**2.7**	**3.0**	**3.0**	**3.0**	**3.1**	**3.0**	**3.1**
	Top 10 Average	3.2	3.5	3.5	3.6	3.6	3.5	3.6
	Bottom 10 Average	2.2	2.5	2.5	2.4	2.5	2.4	2.6
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**2.5**	**2.8**	**2.8**	**2.8**	**2.9**	**2.8**	**2.9**
	Top 10 Average	3.1	3.4	3.4	3.4	3.5	3.3	3.5
	Bottom 10 Average	1.9	2.2	2.3	2.2	2.3	2.2	2.3
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**2.6**	**2.9**	**3.0**	**3.0**	**3.0**	**2.9**	**3.0**
	Top 10 Average	3.2	3.6	3.5	3.6	3.6	3.5	3.6
	Bottom 10 Average	2.0	2.4	2.4	2.4	2.4	2.3	2.4
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**2.8**	**3.1**	**3.1**	**3.1**	**3.1**	**3.0**	**3.2**
	Top 10 Average	3.4	3.7	3.7	3.7	3.7	3.6	3.7
	Bottom 10 Average	2.1	2.5	2.5	2.5	2.5	2.4	2.5
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**2.9**	**3.2**	**3.3**	**3.3**	**3.3**	**3.2**	**3.3**
	Top 10 Average	3.5	3.9	3.9	3.9	3.9	3.8	4.0
	Bottom 10 Average	2.3	2.6	2.7	2.6	2.6	2.6	2.7
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**3.3**	**3.5**	**3.5**	**3.6**	**3.6**	**3.5**	**3.6**
	Top 10 Average	3.9	4.2	4.2	4.2	4.2	4.1	4.3
	Bottom 10 Average	2.7	2.9	2.9	3.0	3.0	2.9	3.0
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**3.6**	**3.8**	**3.8**	**3.9**	**3.9**	**3.8**	**3.9**
	Top 10 Average	4.2	4.5	4.4	4.5	4.5	4.4	4.6
	Bottom 10 Average	2.9	3.1	3.1	3.2	3.3	3.1	3.3
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**4.2**	**4.3**	**4.4**	**4.4**	**4.4**	**4.3**	**4.5**
	Top 10 Average	4.9	5.0	5.0	5.0	5.0	5.0	5.1
	Bottom 10 Average	3.5	3.7	3.7	3.8	3.8	3.7	3.8
13. Corporate Aaa Bond Yield	**CONSENSUS**	**5.2**	**5.4**	**5.4**	**5.4**	**5.5**	**5.4**	**5.5**
	Top 10 Average	5.7	5.9	5.9	6.0	5.9	5.9	6.0
	Bottom 10 Average	4.7	4.9	4.9	4.9	5.0	4.9	5.1
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.1**	**6.3**	**6.3**	**6.3**	**6.3**	**6.3**	**6.4**
	Top 10 Average	6.8	7.0	6.9	7.0	6.9	6.9	7.0
	Bottom 10 Average	5.5	5.6	5.7	5.6	5.8	5.6	5.7
14. State & Local Bonds Yield	**CONSENSUS**	**4.6**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.8**
	Top 10 Average	5.1	5.3	5.2	5.3	5.3	5.2	5.3
	Bottom 10 Average	4.2	4.2	4.2	4.1	4.1	4.2	4.2
15. Home Mortgage Rate	**CONSENSUS**	**5.3**	**5.5**	**5.5**	**5.5**	**5.5**	**5.4**	**5.6**
	Top 10 Average	5.9	6.2	6.1	6.2	6.1	6.1	6.2
	Bottom 10 Average	4.6	4.8	4.8	4.7	4.9	4.8	4.9
A. FRB - Major Currency Index	**CONSENSUS**	**93.8**	**93.2**	**93.1**	**93.0**	**92.7**	**93.2**	**92.5**
	Top 10 Average	96.5	96.6	96.9	97.1	97.2	96.9	97.1
	Bottom 10 Average	91.0	89.7	89.2	88.7	88.1	89.3	88.1

		----------Year-Over-Year, % Change----------					Five-Year Averages	
		2019	**2020**	**2021**	**2022**	**2023**	**2019-2023**	**2024-2028**
B. Real GDP	**CONSENSUS**	**2.2**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.1**
	Top 10 Average	2.6	2.4	2.4	2.4	2.3	2.4	2.3
	Bottom 10 Average	1.7	1.6	1.6	1.6	1.6	1.6	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.1**	**2.1**	**2.0**	**2.0**	**2.1**	**2.0**
	Top 10 Average	2.5	2.3	2.3	2.2	2.2	2.3	2.3
	Bottom 10 Average	1.9	1.9	1.9	1.9	1.7	1.8	1.9
D. Consumer Price Index	**CONSENSUS**	**2.3**	**2.3**	**2.3**	**2.3**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.6	2.6	2.5	2.5	2.4	2.5	2.4
	Bottom 10 Average	1.9	2.0	2.0	2.1	1.8	2.0	2.0

Value Line Forecast for the U.S. Economy

	Actual					Estimated				
	2012	2013	2014	2015	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Gross Domestic Product and its Components (2009 Chain Weighted $) Billions of Dollars										
Final Sales	15292	15612	16014	16472	16716	***17141***	***17599***	***18039***	***18454***	***18860***
Total Consumption	10413	10565	10868	11264	11572	***11882***	***12235***	***12602***	***12955***	***13305***
Nonresidential Fixed Investment	1964	2033	2173	2224	2211	***2306***	***2399***	***2495***	***2595***	***2699***
Structures	423	429	474	466	447	***477***	***482***	***494***	***511***	***531***
Equipment & Software	939	982	1048	1084	1048	***1086***	***1135***	***1180***	***1215***	***1240***
Residential Fixed Investment	437	488	506	557	588	***601***	***627***	***652***	***672***	***689***
Exports	1963	2032	2119	2127	2120	***2200***	***2285***	***2377***	***2472***	***2546***
Imports	2410	2436	2546	2673	2706	***2813***	***2947***	***3080***	***3203***	***3331***
Federal Government	1214	1143	1115	1114	1115	***1116***	***1126***	***1115***	***1104***	***1093***
State & Local Governments	1728	1714	1723	1763	1784	***1787***	***1796***	***1814***	***1833***	***1851***
Gross Domestic Product	16155	16692	17428	18121	18625	***19356***	***20294***	***21279***	***22291***	***23306***
Real GDP (2009 Chain Weighted $)	15355	15612	15982	16397	16716	***17075***	***17544***	***18000***	***18432***	***18838***
Prices and Wages — Annual Rates of Change										
GDP Deflator	1.8	1.6	1.8	1.1	1.5	***1.7***	***2.2***	***2.2***	***2.3***	***2.3***
CPI-All Urban Consumers	2.1	1.5	1.6	0.5	1.8	***1.5***	***2.1***	***2.2***	***2.6***	***2.5***
PPI-Finished Goods	1.9	1.2	1.9	-3.3	1.1	***1.8***	***1.5***	***1.6***	***2.3***	***2.2***
Employment Cost Index—Total Comp.	1.9	1.9	2.1	1.9	2.2	***2.8***	***2.9***	***3.2***	***3.3***	***3.4***
Productivity	0.9	0.0	0.7	0.7	0.9	***1.1***	***1.7***	***1.4***	***1.4***	***1.5***
Production and Other Key Measures										
Industrial Prod. (% Change, Annualized)	2.8	1.9	3.7	-2.7	-0.1	***2.5***	***2.7***	***2.8***	***2.3***	***2.0***
Factory Operating Rate (%)	74.5	74.1	75.3	75.5	75.1	***75.5***	***75.8***	***76.0***	***75.5***	***75.0***
Nonfarm Inven. Change (2009 Chain Weighted $)	72.7	54.3	65.0	102.8	34.5	***3.8***	***25.8***	***35.0***	***40.0***	***30.0***
Housing Starts (Mill. Units)	0.78	0.93	1.00	1.11	1.18	***1.21***	***1.35***	***1.40***	***1.43***	***1.40***
Existing House Sales (Mill. Units)	4.66	5.07	4.92	5.24	5.44	***5.58***	***5.62***	***5.55***	***5.50***	***5.50***
Total Light Vehicle Sales (Mill. Units)	14.4	15.5	16.4	17.4	17.5	***17.1***	***17.3***	***17.2***	***17.1***	***17.0***
National Unemployment Rate (%)	8.1	7.4	6.2	5.3	4.9	***4.4***	***4.2***	***4.1***	***4.2***	***4.2***
Federal Budget Surplus (Unified, FY, $Bill)	-1089	-680	-483	-477	-581	***-613***	***-510***	***-700***	***-750***	***-800***
Price of Oil ($Bbl., U.S. Refiners' Cost)	101.00	100.47	92.23	48.40	40.60	***46.25***	***47.50***	***48.00***	***55.00***	***60.00***
Money and Interest Rates										
3-Month Treasury Bill Rate (%)	0.1	0.1	0.1	0.1	0.3	***1.0***	***1.8***	***2.5***	***2.7***	***2.8***
Federal Funds Rate (%)	0.1	0.1	0.1	0.1	0.4	***1.0***	***1.8***	***2.8***	***2.8***	***3.0***
10-Year Treasury Note Rate (%)	1.8	2.4	2.5	2.2	1.9	***2.4***	***3.1***	***3.4***	***3.7***	***4.0***
Long-Term Treasury Bond Rate (%)	2.9	3.5	3.3	2.9	2.6	***3.0***	***3.6***	***3.8***	***4.0***	***4.0***
AAA Corporate Bond Rate (%)	3.7	4.2	4.2	3.9	3.7	***3.9***	***4.6***	***5.2***	***5.4***	***5.6***
Prime Rate (%)	3.3	3.3	3.3	3.3	3.5	***4.1***	***4.5***	***5.5***	***6.0***	***6.0***
Incomes										
Personal Income (Annualized % Change)	5.0	1.1	4.4	4.1	1.6	***4.1***	***3.8***	***5.0***	***5.2***	***5.0***
Real Disp. Inc. (Annualized % Change)	3.1	-1.4	2.7	3.2	0.3	***3.0***	***3.3***	***3.2***	***3.0***	***2.8***
Personal Savings Rate (%)	7.6	4.8	4.8	6.1	4.9	***3.9***	***4.7***	***5.2***	***5.3***	***5.5***
After-Tax Profits (Annualized $Bill)	1683	1693	1694	1657	1692	***1841***	***2057***	***2200***	***2310***	***2426***
Yr-to-Yr % Change	17.9	0.6	0.1	-2.2	2.1	***8.8***	***11.7***	***7.0***	***5.0***	***5.0***
Composition of Real GDP-Annual Rates of Change										
Gross Domestic Product	2.2	1.7	2.4	2.6	1.9	***2.1***	***2.8***	***2.6***	***2.4***	***2.2***
Final Sales	2.1	2.1	2.6	2.9	1.5	***2.5***	***2.7***	***2.5***	***2.3***	***2.2***
Total Consumption	1.5	1.5	2.9	3.6	2.7	***2.7***	***3.0***	***3.0***	***2.8***	***2.7***
Nonresidential Fixed Investment	9.0	3.5	6.9	2.3	-0.6	***4.3***	***4.0***	***4.0***	***4.0***	***4.0***
Structures	12.9	1.4	10.5	-1.8	-4.1	***6.8***	***1.0***	***2.5***	***3.5***	***4.0***
Equipment & Software	10.8	4.6	6.7	3.5	-3.4	***3.7***	***4.4***	***4.0***	***3.0***	***2.0***
Residential Fixed Investment	13.5	11.7	3.6	10.1	5.6	***2.3***	***4.3***	***4.0***	***3.0***	***2.5***
Exports	3.4	3.5	4.3	0.4	-0.3	***3.8***	***3.9***	***4.0***	***4.0***	***3.0***
Imports	2.2	1.1	4.5	5.0	1.3	***4.0***	***4.8***	***4.5***	***4.0***	***4.0***
Federal Government	-1.9	-5.8	-2.4	-0.1	0.1	***0.2***	***0.9***	***-1.0***	***-1.0***	***-1.0***
State & Local Governments	-1.9	-0.8	0.5	2.3	1.2	***0.2***	***0.5***	***1.0***	***1.0***	***1.0***

Concept	SeriesType	Last Update	2012	2013	2014	2015	2016	2017	2018	2019
Yield On 30-Year Treasury Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	2.92	3.45	3.34	2.84	2.60	3.05	3.75	4.36
Gross Domestic Product	U.S. Macro - 30 Year Baseline	8/24/2017	16,155.25	16,691.50	17,427.60	18,120.70	18,624.45	19,359.28	20,317.56	21,259.07
Yield On 10-Year Treasury Notes	U.S. Macro - 30 Year Baseline	8/24/2017	1.80	2.35	2.54	2.14	1.84	2.40	3.12	3.84
Yield On Aaa-Rated Corporate Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	3.67	4.24	4.16	3.89	3.67	3.88	4.77	5.21
Rate On Aa-Rated Public Utility Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	3.83	4.24	4.19	3.99	3.73	3.92	5.08	5.76

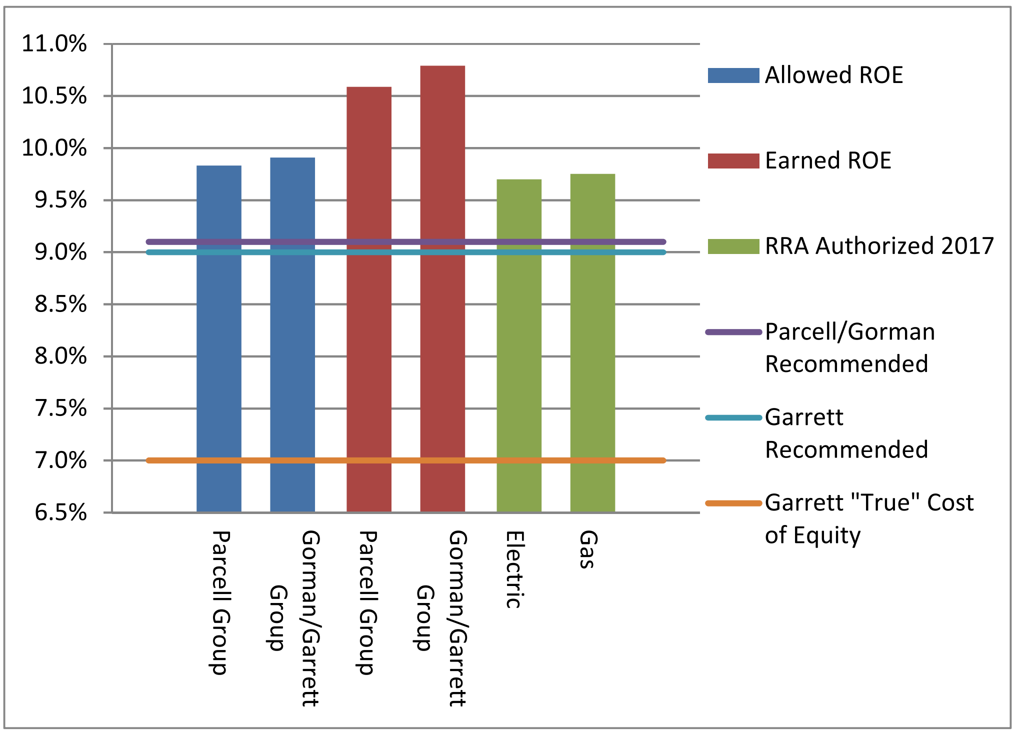
Concept	SeriesType	Last Update	2020	2021	2022	2023	2024	2025	2026	2027
Yield On 30-Year Treasury Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57
Gross Domestic Product	U.S. Macro - 30 Year Baseline	8/24/2017	22,206.43	23,209.89	24,208.61	25,222.39	26,254.16	27,310.25	28,399.91	29,528.53
Yield On 10-Year Treasury Notes	U.S. Macro - 30 Year Baseline	8/24/2017	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06
Yield On Aaa-Rated Corporate Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45
Rate On Aa-Rated Public Utility Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03

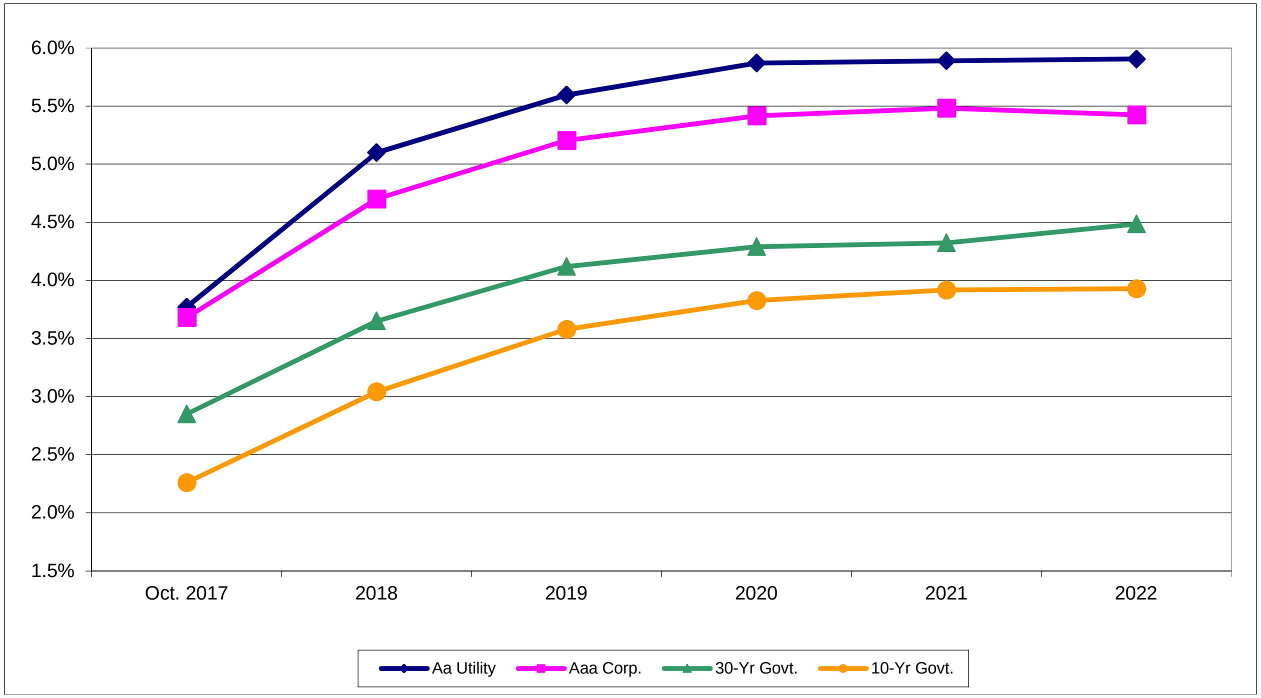
Concept	SeriesType	Last Update	2028	2029	2030	2031	2032	2033	2034	2035
Yield On 30-Year Treasury Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57
Gross Domestic Product	U.S. Macro - 30 Year Baseline	8/24/2017	30,724.30	31,976.52	33,280.14	34,643.80	36,055.12	37,526.86	39,064.29	40,649.42
Yield On 10-Year Treasury Notes	U.S. Macro - 30 Year Baseline	8/24/2017	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06
Yield On Aaa-Rated Corporate Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45
Rate On Aa-Rated Public Utility Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03

Concept	SeriesType	Last Update	2036	2037	2038	2039	2040	2041	2042	2043
Yield On 30-Year Treasury Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57
Gross Domestic Product	U.S. Macro - 30 Year Baseline	8/24/2017	42,320.67	44,051.28	45,840.19	47,706.15	49,643.90	51,664.92	53,778.59	56,003.54
Yield On 10-Year Treasury Notes	U.S. Macro - 30 Year Baseline	8/24/2017	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06
Yield On Aaa-Rated Corporate Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45
Rate On Aa-Rated Public Utility Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03

Concept	SeriesType	Last Update	2044	2045	2046	2047
Yield On 30-Year Treasury Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	4.57	4.57	4.57	4.57
Gross Domestic Product	U.S. Macro - 30 Year Baseline	8/24/2017	58,326.65	60,746.89	63,251.52	65,892.70
Yield On 10-Year Treasury Notes	U.S. Macro - 30 Year Baseline	8/24/2017	4.06	4.06	4.06	4.06
Yield On Aaa-Rated Corporate Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	5.45	5.45	5.45	5.45
Rate On Aa-Rated Public Utility Bonds	U.S. Macro - 30 Year Baseline	8/24/2017	6.03	6.03	6.03	6.03

	Parcell Gr	Gorman/(	Parcell Gr	Gorman/Ga	Electric	Gas	
	9.83%	9.91%					
			0.1059	0.1079			
					0.097	0.0975	
0.091	0.091	0.091	0.091	0.091	0.091	0.091	0.091
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07



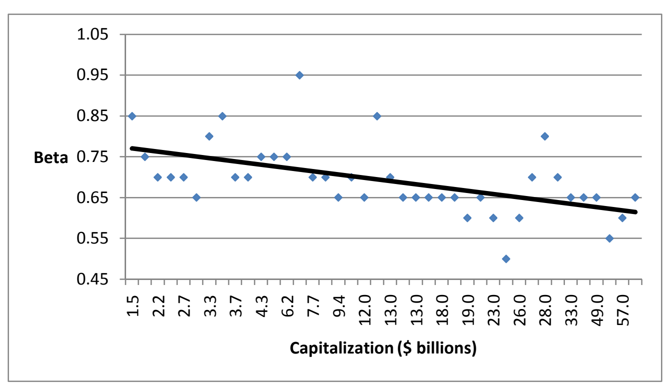


<u>Source:</u>
Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 1, 2017)
IHS Global Insight (Aug. 24, 2017)
Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 36, No. 6 (Jun. 1, 2017)

	Oct. 2017	2018	2019	2020	2021	2022	Diff
10-Yr. Treasury	2.3%	3.0%	3.6%	3.8%	3.9%	3.9%	1.7%
30-Yr. Treasury	2.9%	3.7%	4.1%	4.3%	4.3%	4.5%	1.6%
Aaa Corporate	3.7%	4.7%	5.2%	5.4%	5.5%	5.4%	1.7%
Aa Utility	3.8%	5.1%	5.6%	5.9%	5.9%	5.9%	2.1%
							1.8%

ELECTRIC UTILITY COMPANIES RANKED BY SIZE
RISK INDICATORS

COMPANY	CAP ($000) Value Line	BETA	
Otter Tail Corp	1.5	0.85	1,500,000
El Paso Electric Co.	2.1	0.75	2,100,000
MGE Energy Inc.	2.2	0.70	2,200,000
Avista Corp.	2.6	0.70	2,600,000
PNM Resources	2.7	0.70	2,700,000
NorthWestern	2.9	0.65	2,900,000
ALLETE	3.3	0.80	3,300,000
Black Hills Corp.	3.7	0.85	3,700,000
Hawaiian Electric Industries, Inc.	3.7	0.70	3,700,000
Portland General	4.1	0.70	4,100,000
IDACORP	4.3	0.75	4,300,000
Vectren	4.7	0.75	4,700,000
Great Plains Energy Inc.	6.2	0.75	6,200,000
OGE Energy Corp.	7.3	0.95	7,300,000
Westar Energy, Inc.	7.7	0.70	7,700,000
Alliant Energy	8.9	0.70	8,900,000
SCANA Corp.	9.4	0.65	9,400,000
Pinnacle West Capital Corp.	9.6	0.70	9,600,000
CMS Energy Corp.	12.0	0.65	12,000,000
CenterPoint Energy, Inc.	12.0	0.85	12,000,000
Ameren Corp.	13.0	0.70	13,000,000
Entergy Corp.	13.0	0.65	13,000,000
FirstEnergy Corp.	13.0	0.65	13,000,000
Fortis	17.0	0.65	17,000,000
DTE Energy Company	18.0	0.65	18,000,000
Eversource Energy	19.0	0.65	19,000,000
WEC Energy Group	19.0	0.60	19,000,000
Public Service Enterprise Group, Inc.	22.0	0.65	22,000,000
Xcel Energy Inc.	23.0	0.60	23,000,000
Consolidated Edison, Inc.	24.0	0.50	24,000,000
Edison International	26.0	0.60	26,000,000
PPL Corp	26.0	0.70	26,000,000
Sempra Energy	28.0	0.80	28,000,000
Exelon Corp.	31.0	0.70	31,000,000
American Electric Power Company	33.0	0.65	33,000,000
PG&E Corp.	34.0	0.65	34,000,000
Dominion Resources	49.0	0.65	49,000,000
Southern Company	50.0	0.55	50,000,000
Duke Energy Corp.	57.0	0.60	57,000,000
NextEra Energy, Inc.	63.0	0.65	63,000,000
	-		
Avangrid	14.0	nmf	14,000,000



Source: Exhibit DCP-16.

ALLOWED ROE **Exhibit No.___(AMM-15)**
Page 1 of 1

PARCELL PROXY GROUP

	Company		**Allowed ROE (a)**	
1	ALLETE		10.38%	
2	Alliant Energy		10.50%	
3	Avista Corp.		9.50%	
4	Black Hills Corp		9.37%	
5	El Paso Electric Co.		9.48%	
6	Hawaiian Electric Industries		9.67%	
7	IDACORP		10.00%	
8	NorthWestern Corp		9.92%	
9	OGE Energy		9.73%	
10	Otter Tail Corp		NA	
11	Pinnacle West Capital		10.00%	
12	Portland General Corp		9.60%	
13	PNM Resources		10.00%	
14	SCANA Corp		10.07%	
15	Vectren		10.28%	
	Range of Reasonableness	**9.37%**	--	**10.50%**
	Midpoint		**9.94%**	
	Average		**9.83%**	

GORMAN/GARRETT PROXY GROUP

	Company (b)		**Allowed ROE (a)**	
1	ALLETE, Inc.		10.38%	
2	Ameren Corporation		9.15%	
3	Avangrid, Inc.		9.23%	
4	Black Hills Corporation		9.37%	
5	CMS Energy Corporation		10.10%	
6	Dominion Resources, Inc.		10.90%	
7	DTE Energy Company		10.10%	
8	Edison International		10.45%	
9	El Paso Electric Company		9.48%	
10	Exelon Corporation		9.60%	
11	Hawaiian Electric Industries, Inc.		9.67%	
12	IDACORP, Inc.		10.00%	
13	NorthWestern Corporation		9.92%	
14	Otter Tail Corporation		NA	
15	PG&E Corporation		10.40%	
16	Portland General Electric Company		9.60%	
17	Sempra Energy		10.20%	
	Range of Reasonableness	**9.15%**	--	**10.90%**
	Midpoint		**10.03%**	
	Average		**9.91%**	

(a) The Value Line Investment Survey (Aug. 18, Sep. 15, & Oct. 27, 2017).

(b) On July 19, 2017, Hydro One announced that it was acquiring Avista Corp. For this reason, Mr. Gorman eliminated Avista from his proxy group and I assume that Mr. Garrett would do the same.

EXPECTED EARNINGS APPROACH — **Exhibit No.___(AMM-16)**

Page 1 of 1

PARCELL PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.0%	1.0260	9.2%
2	Alliant Energy	13.0%	1.0044	13.1%
3	Avista Corp.	8.5%	1.0346	8.8%
4	Black Hills Corp	10.5%	1.0436	11.0%
5	El Paso Electric Co.	9.5%	1.0218	9.7%
6	Hawaiian Electric Industries	9.0%	1.0174	9.2%
7	IDACORP	12.0%	1.0195	12.2%
8	NorthWestern Corp	10.0%	1.0177	10.2%
9	OGE Energy	12.0%	1.0184	12.2%
10	Otter Tail Corp	10.0%	1.0377	10.4%
11	Pinnacle West Capital	10.5%	1.0204	10.7%
12	Portland General Corp	9.5%	1.0181	9.7%
13	PNM Resources	9.0%	1.0150	9.1%
14	SCANA Corp	11.0%	1.0013	11.0%
15	Vectren	12.0%	1.0299	12.4%
	Average			**10.6%**

GORMAN/GARRETT PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE, Inc.	9.0%	1.0260	9.2%
2	Ameren Corporation	10.0%	1.0268	10.3%
3	Avangrid, Inc.	5.0%	1.0064	5.0%
4	Black Hills Corporation	10.5%	1.0436	11.0%
5	CMS Energy Corporation	13.5%	1.0356	14.0%
6	Dominion Resources, Inc.	19.0%	1.0025	19.0%
7	DTE Energy Company	10.5%	1.0258	10.8%
8	Edison International	12.0%	1.0195	12.2%
9	El Paso Electric Company	9.5%	1.0218	9.7%
10	Exelon Corporation	9.5%	1.0260	9.7%
11	Hawaiian Electric Industries, Inc.	9.0%	1.0174	9.2%
12	IDACORP, Inc.	12.0%	1.0195	12.2%
13	NorthWestern Corporation	10.0%	1.0177	10.2%
14	Otter Tail Corporation	10.0%	1.0377	10.4%
15	PG&E Corporation	10.0%	1.0302	10.3%
16	Portland General Electric Company	9.5%	1.0181	9.7%
17	Sempra Energy	13.0%	1.0039	13.1%
	Average (d)			**10.8%**

(a) The Value Line Investment Survey (Aug. 18, Sep. 15, & Oct. 27, 2017)
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity)
(c) (a) x (b).
(d) Excludes highlighted values

REVISED GORMAN RISK PREMIUM **Exhibit No.__(AMM-17)**
Page 1 of 4

TREASURY BOND YIELD

	(a) **Treasury Bond Yield**	(a) **Authorized Electric Returns**	(a) **Indicated Risk Premium**
1986	7.80%	13.93%	6.13%
1987	8.58%	12.99%	4.41%
1988	8.96%	12.79%	3.83%
1989	8.45%	12.97%	4.52%
1990	8.61%	12.70%	4.09%
1991	8.14%	12.55%	4.41%
1992	7.67%	12.09%	4.42%
1993	6.60%	11.41%	4.81%
1994	7.37%	11.34%	3.97%
1995	6.88%	11.55%	4.67%
1996	6.70%	11.39%	4.69%
1997	6.61%	11.40%	4.79%
1998	5.58%	11.66%	6.08%
1999	5.87%	10.77%	4.90%
2000	5.94%	11.43%	5.49%
2001	5.49%	11.09%	5.60%
2002	5.43%	11.16%	5.73%
2003	4.96%	10.97%	6.01%
2004	5.05%	10.75%	5.70%
2005	4.65%	10.54%	5.89%
2006	4.90%	10.34%	5.44%
2007	4.83%	10.31%	5.48%
2008	4.28%	10.37%	6.09%
2009	4.07%	10.52%	6.45%
2010	4.25%	10.29%	6.04%
2011	3.91%	10.19%	6.28%
2012	2.92%	10.01%	7.09%
2013	3.45%	9.81%	6.36%
2014	3.34%	9.75%	6.41%
2015	2.84%	9.60%	6.76%
2016	2.60%	9.60%	7.00%
2017(thru 2Q)	2.97%	9.61%	6.64%
AVERAGE	5.61%	11.12%	5.51%

IMPLIED COST OF EQUITY

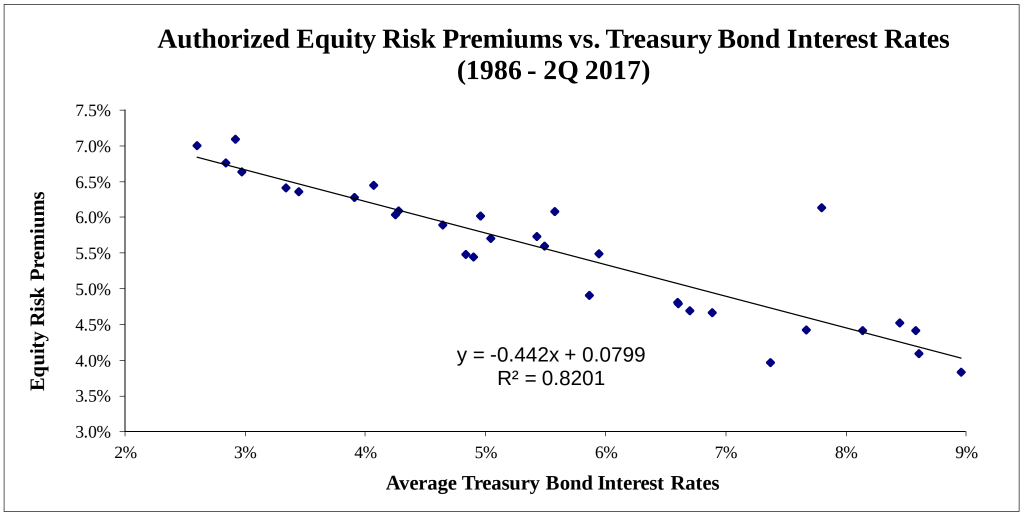
Projected Treasury Bond Yield (b)	3.60%
Average Treasury Bond Yield Over Study Period	5.61%
Change in Bond Yield	-2.01%
Risk Premium/Interest Rate Coefficient (c)	-44.20%
Adjustment to Study Period Risk Premium	0.89%
Average Risk Premium Over Study Period	5.51%
Interest Rate Adjustment	0.89%
Adjusted Equity Risk Premium	6.40%
Projected Treasury Bond Yield (b)	3.60%
Implied Cost of Equity	**10.00%**

(a) Exhibit No. MPG-16.
(b) Gorman Direct at 53.
(c) See regression data on page 2 of this Exhibit.

REVISED GORMAN RISK PREMIUM

Exhibit No.__(AMM-17)
Page 2 of 4

REGRESSION OUTPUT - TREASURY BOND YIELD



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.905582993
R Square	0.820080558
Adjusted R Square	0.814083243
Standard Error	0.004018312
Observations	32

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.002207939	0.002207939	136.7412905	1.06187E-12
Residual	30	0.000484405	1.61468E-05		
Total	31	0.002692344			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.079881673	0.002238119	35.69143322	3.91524E-26	0.075310825	0.084452522	0.075310825	0.084452522
X Variable 1	-0.442009906	0.037799161	-11.69364317	1.06187E-12	-0.519206092	-0.36481372	-0.519206092	-0.364813719

REVISED GORMAN RISK PREMIUM **Exhibit No.__(AMM-17)**
Page 3 of 4

UTILITY BOND YIELD

	(a) **Moody's "A" Rated Public Utility Bond Yield**	(a) **Authorized Electric Returns**	(a) **Indicated Risk Premium**
1986	9.58%	13.93%	4.35%
1987	10.10%	12.99%	2.89%
1988	10.49%	12.79%	2.30%
1989	9.77%	12.97%	3.20%
1990	9.86%	12.70%	2.84%
1991	9.36%	12.55%	3.19%
1992	8.69%	12.09%	3.40%
1993	7.59%	11.41%	3.82%
1994	8.31%	11.34%	3.03%
1995	7.89%	11.55%	3.66%
1996	7.75%	11.39%	3.64%
1997	7.60%	11.40%	3.80%
1998	7.04%	11.66%	4.62%
1999	7.62%	10.77%	3.15%
2000	8.24%	11.43%	3.19%
2001	7.76%	11.09%	3.33%
2002	7.37%	11.16%	3.79%
2003	6.58%	10.97%	4.39%
2004	6.16%	10.75%	4.59%
2005	5.65%	10.54%	4.89%
2006	6.07%	10.34%	4.27%
2007	6.07%	10.31%	4.24%
2008	6.53%	10.37%	3.84%
2009	6.04%	10.52%	4.48%
2010	5.46%	10.29%	4.83%
2011	5.04%	10.19%	5.15%
2012	4.13%	10.01%	5.88%
2013	4.48%	9.81%	5.33%
2014	4.28%	9.75%	5.47%
2015	4.12%	9.60%	5.48%
2016	3.93%	9.60%	5.67%
2017(thru 2Q)	4.12%	9.61%	5.49%
AVERAGE	6.99%	11.12%	4.13%

INDICATED COST OF EQUITY

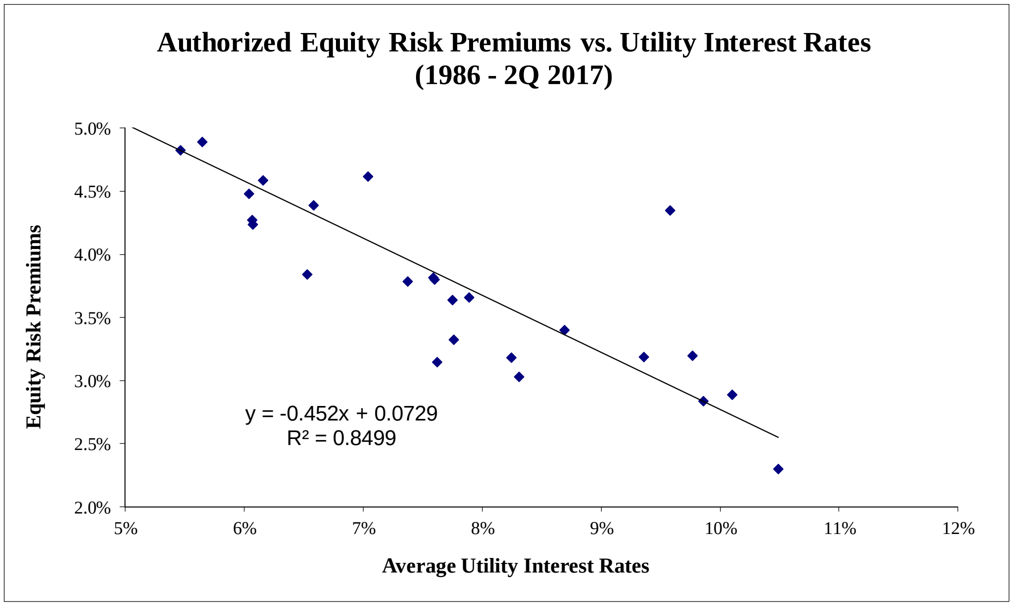
Current Baa Utility Bond Yield (b)	4.27%
Average Utility Bond Yield Over Study Period	6.99%
Change in Bond Yield	-2.72%
Risk Premium/Interest Rate Coefficient (c)	-45.20%
Adjustment to Study Period Risk Premium	1.23%
Average Risk Premium Over Study Period	4.13%
Interest Rate Adjustment	1.23%
Adjusted Equity Risk Premium	5.36%
Current Baa Utility Bond Yield (b)	4.27%
Implied Cost of Equity	**9.63%**

(a) Exhibit No. MPG-17.
(b) Gorman Direct at 53.
(c) See regression data on page 4 of this Exhibit.

REVISED GORMAN RISK PREMIUM

Exhibit No.__(AMM-17)
Page 4 of 4

REGRESSION OUTPUT - UTILITY BOND YIELD



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.921914078
R Square	0.849925567
Adjusted R Square	0.844923086
Standard Error	0.003782283
Observations	32

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.002430544	0.002430544	169.9008052	6.87551E-14
Residual	30	0.00042917	1.43057E-05		
Total	31	0.002859714			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072904364	0.002514212	28.99690365	1.67796E-23	0.067769658	0.07803907	0.067769658	0.07803907
X Variable 1	-0.451956408	0.034673592	-13.03460031	6.87551E-14	-0.522769329	-0.381143487	-0.522769329	-0.381143487

6-MONTH AVERAGE BOND YIELDS

	(a) Public Utility Bonds Baa	A	Aa	AVG.	(b) 30-Yr. Treas	(b) 10-Yr. Treas	(a) Aaa Corp.
May	4.50%	4.13%	3.94%	4.19%	2.96%	2.30%	3.85%
Jun.	4.32%	3.94%	3.77%	4.01%	2.80%	2.19%	3.68%
Jul.	4.36%	3.99%	3.82%	4.06%	2.88%	2.32%	3.70%
Aug.	4.23%	3.86%	3.67%	3.92%	2.80%	2.21%	3.63%
Sep.	4.24%	3.87%	3.70%	3.93%	2.78%	2.20%	3.63%
Oct. 2017	4.26%	3.91%	3.74%	3.97%	2.88%	2.36%	3.60%
Average	**4.32%**	**3.95%**	**3.77%**	**4.01%**	**2.85%**	**2.26%**	**3.68%**
Aa Spread	**0.55%**	**0.18%**		**0.24%**	**0.59%**		

(a) Moody's Investors Service.
(b) http://www.fred.stlouisfed.org

BOND YIELD FORECAST

	Baa Yield 2018-22		Average Utility 2018-22
Projected Aa Utility Yield			
IHS Global Insight (a)	5.79%		5.79%
EIA (b)	5.56%		5.56%
Average	5.67%		5.67%
Current Baa - Aa Yield Spread (c)	0.55%	Avg. - Aa Spread	0.24%
Implied Baa Utility Yield	**6.22%**	**Implied Avg Yield**	**5.91%**

(a) IHS Global Insight (Aug. 24, 2017)
(b) Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period May - Oct. 2017.

	2018	2019	2020	2021	2022	Average 2018-22
10-Yr. Treasury						
Value Line (a)	3.1%	3.4%	3.7%	4.0%		
IHS Global Insight (b)	3.12%	3.84%	4.06%	4.06%	4.06%	
EIA (c)	2.88%	3.48%	3.75%	3.81%	3.83%	
Blue Chip (d)	3.1%	3.6%	3.8%	3.8%	3.9%	
30-Yr. Treasury						
Value Line (a)	3.6%	3.8%	4.0%	4.0%		3.9%
IHS Global Insight (b)	3.75%	4.36%	4.57%	4.57%	4.57%	4.4%
Blue Chip (d)	3.6%	4.2%	4.3%	4.4%	4.4%	4.2%
						4.1%
Aaa Corporate						
Value Line (a)	4.6%	5.2%	5.4%	5.6%		
IHS Global Insight (b)	4.77%	5.21%	5.45%	5.45%	5.45%	
Blue Chip (d)	4.7%	5.2%	5.4%	5.4%	5.4%	
Aa Utility						
IHS Global Insight (b)	5.08%	5.76%	6.03%	6.03%	6.03%	5.79%
EIA (c)	5.12%	5.43%	5.71%	5.75%	5.78%	5.56%

(a) Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 1, 2017)
(b) IHS Global Insight (Aug. 24, 2017)
(c) Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
(d) *Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 36, No. 6 (Jun. 1, 2017)*

BLUE CHIP (Jun. 2017)

	1Q2017	2022	Chg.
Aaa	4.10	5.4	1.3
Baa	4.68	6.3	1.62
			1.46

Society of Utility and
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Financial Analysts

THE COST OF CAPITAL –

A PRACTITIONER'S GUIDE

BY

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Author's Note: This manual has been prepared as an educational reference on cost of capital concepts. Its purpose is to describe a broad array of cost of capital models and techniques. No cost of equity model or other concept is recommended or emphasized, nor is any procedure for employing any model recommended. Furthermore, no opinions or preferences are expressed by either the author or the Society of Utility and Regulatory Financial Analysts.

CHAPTER 7
COMPARABLE EARNINGS

The comparable earnings method ("CE" or "CEM") is the "granddaddy" of cost of equity methods, as it is derived from the "corresponding risk" standard of the *Bluefield* and *Hope* cases. This method is based upon the economic concept of "opportunity cost." As noted previously the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk. If, in the opinion of those who save and commit capital, the prospective return from a given investment is not equal to that available from other investments of similar risk, the available capital will tend to be shifted to the alternative investments. Through this mechanism, opportunity-cost-driven pricing signals direct capital to its most productive uses; thus, a free enterprise system promotes an efficient allocation of scarce resources.

The established legal standards are consistent with the opportunity cost principle. The two Supreme Court cases most frequently cited (*Bluefield* and *Hope*) hold that: the return to the equity owners be sufficient to maintain the credit of the enterprise and confidence in its financial integrity; to permit the enterprise to attract required additional capital on reasonable terms; and, to provide the enterprise and its investors with an earnings opportunity commensurate with the returns available on investments in other enterprises having corresponding risks.

These three interrelated criteria constitute a succinct statement of the opportunity cost principle. An expected return on equity equal to that which can be realized on alternative investments of corresponding risk will, in turn, be sufficient to assure confidence in the financial integrity of the enterprise, to maintain its credit, and to permit it to attract new capital on reasonable terms.

The comparable earnings method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The comparable earnings method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base – rate of return methodology used to set utility rates.

It is maintained that the comparable earnings standard is easy to calculate and the amount of subjective judgment required is minimal. The method avoids several of the subjective factors involved in other cost of capital methodologies. For example, the DCF method requires the determination of the growth rate contemplated by investors, which is a subjective factor. The CAPM requires the specification of several expectational variables, such as market return and beta. In contrast, the comparable earnings approach makes use of readily available accounting data.

In addition, this method is easily understood and is firmly anchored in regulatory tradition (i.e., *Bluefield* and *Hope*). The method is not influenced by the regulatory process to the same extent as market-based methods such as DCF and CAPM. The base to which the comparable earnings standard is applied is the utility's book common equity, which is much less vulnerable to regulatory influences than stock price which is the base to which the market-based standards are applied. Stock price can be influenced by the actions of regulators.

The rationale for the comparable earnings technique is aptly stated by Morin (2006, 394):

> "Although the Comparable Earnings test does not square well with economic theory, the approach is nevertheless meritorious. If the basic purpose of comparable earnings is to set a fair return rather than determine the true economic return, then the argument is academic. If regulators consider a fair return as one that equals the book rates or return earned by comparable risk firms rather than one that is equal to the cost of capital of such firms, the Comparable Earnings test is relevant. This notion of fairness, rooted in the traditional legalistic interpretation of the *Hope* language, validates the Comparable Earnings test."

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
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Vienna, Virginia

the earnings requirement of utilities is determined by applying a percentage rate of return to the book value of a utility's investment, and not on the market value of that investment. Therefore, it stands to reason that a different percentage rate of return than the market cost of capital be applied when the investment base is stated in book value terms rather than market value terms. In a competitive market, investment decisions are taken on the basis of market prices, market values, and market cost of capital. If regulation's role was to duplicate the competitive result perfectly, then the market cost of capital would be applied to the current market value of rate base assets employed by utilities to provide service. But because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful.

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EXAMPLE 9-1

Southeastern Electric's sustainable growth rate is required for upcoming rate case testimony. As a gauge of the expected return on equity, authorized rates of return in recent decisions for eastern U.S. electric utilities as reported by Value Line for 2005 and 2006 averaged 11%, with a standard deviation of 1%. In other words, the majority of utilities were authorized to earn 11%, with the allowed return on equity ranging from 10% to 12%. As a gauge of the expected retention ratio, the average 2006 payout ratio of 34 eastern electric utilities as compiled by Value Line was 60%, which indicates an average retention ratio of 40%, with a standard deviation of 5%. This was consistent with the long-run target retention ratio indicated by the management of Southeastern Electric. It is therefore reasonable to postulate that investors expect a retention ratio ranging from 35% to 45% for the company with a likely value of 40%. In Table 9-4 below, expected retention ratios of 35% to 45% and assumed returns on equity from 10% to 12% are multiplied to produce sustainable growth rates ranging from 3.8% to 5.4% with a likely value of 4.6%.

TABLE 9-4
SUSTAINABLE GROWTH METHOD ILLUSTRATION

Expected	Expected Return on Book Equity (r)		
Retention Ratio (b)	10%	11%	12%
35%	3.5%	3.9%	4.2%
40%	4.0%	4.4%	4.8%
45%	4.5%	5.0%	5.4%

It should be pointed out that published forecasts of the expected return on equity by analysts such as Value Line are sometimes based on end-of-period book equity rather than on average book equity. The following formula[15]

[15] The return on year-end common equity, r, is defined as $r = E/B_t$, where E is earnings per share, and B_t is the year-end book value per share. The return on average common equity, r_a, is defined as: $r_a = E/B_a$ where B_a = average book value per share. The latter is by definition: $B_a = (B_t + B_{t-1})/2$ where B_t is the year-end book equity per share and B_{t-1} is the beginning-of-year book equity per share. Dividing r by r_a and substituting:

$$\frac{r}{r_a} = \frac{E/B_t}{E/B_a} = \frac{B_a}{B_t} + \frac{B_t + B_{t-1}}{2B_t}$$

Solving for r_a, a formula for translating the return on year-end equity into the return on average equity is obtained, using reported beginning-of-the year and end-of-year common equity figures:

$$r_a = r\frac{2B_t}{B_t + B_{t-1}}$$

adjusts the reported end-of-year values so that they are based on average common equity, which is the common regulatory practice:

$$r_a = r_t \frac{2B_t}{B_t + B_{t-1}} \tag{9-10}$$

The sustainable growth method can also be extended to include external financing. From Chapter 8, the expanded growth estimate is given by:

$$g = br + sv$$

where b and r are defined as previously, s is the expected percent growth in number of shares to finance investment, and v is the profitability of the equity investment. The variable s measures the long-run expected stock financing that the utility will undertake. If the utility's investments are growing at a stable rate and if the earnings retention rate is also stable, then s will grow at a stable rate. The variable s can be estimated by taking a weighted average of past percentage increases in the number of shares. This measurement is difficult, however, owing to the sporadic and episodic nature of stock financing, and smoothing techniques must be employed. The variable v is the profitability of the equity investment and can be measured as the difference of market price and book value per share divided by the latter, as discussed in Chapter 8.

There are three problems in the practical application of the sustainable growth method. The first is that it may be even more difficult to estimate what b, r, s, and v investors have in mind than it is to estimate what g they envisage. It would appear far more economical and expeditious to use available growth forecasts and obtain g directly instead of relying on four individual forecasts of the determinants of such growth. It seems only logical that the measurement and forecasting errors inherent in using four different variables to predict growth far exceed the forecasting error inherent in a direct forecast of growth itself.

Second, there is a potential element of circularity in estimating g by a forecast of b and ROE for the utility being regulated, since ROE is determined in large part by regulation. To estimate what ROE resides in the minds of investors is equivalent to estimating the market's assessment of the outcome of regulatory hearings. Expected ROE is exactly what regulatory commissions set in determining an allowed rate of return. In other words, the method requires an estimate of return on equity before it can even be implemented. Common sense would dictate the inconsistency of a return on equity recom-

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.

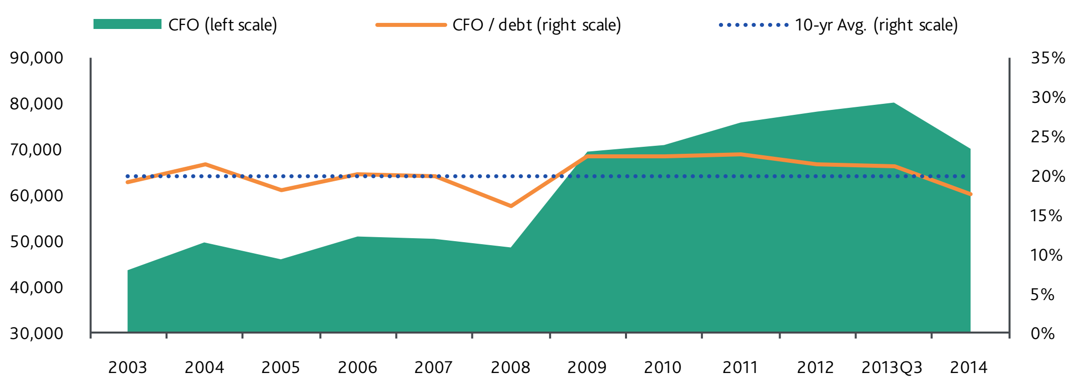
The improved regulatory framework, led by special cost-recovery mechanisms and annual base-rate increases, is all the more important this year for two reasons. First is the end of bonus depreciation, a temporary tax break that expired on December 31. We incorporate a view that bonus depreciation will 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.

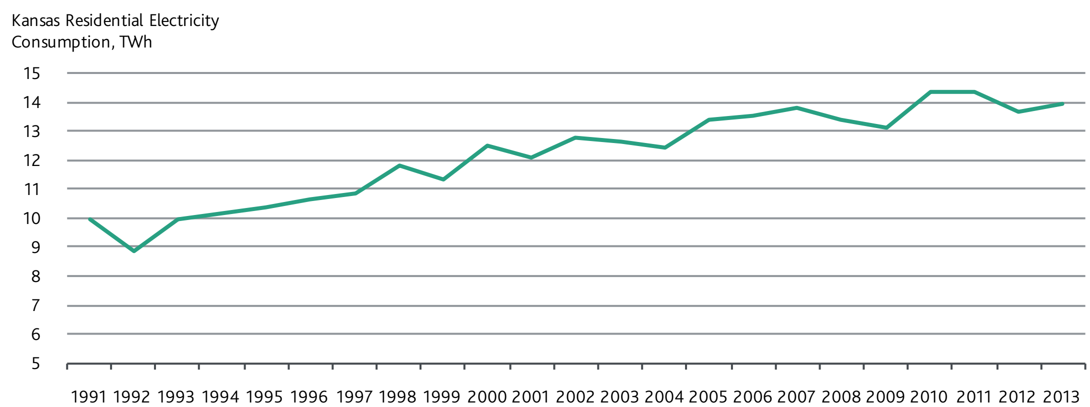
Puget Sound Energy Inc.'s (PSE; Baa1 stable) June 2013 rate order is a good example. Its regulator, the Washington Utilities and Transportation Commission, approved the decoupling of electric and gas revenue from sales volume, and a property-tax tracker that provides more-efficient recovery of property-tax 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



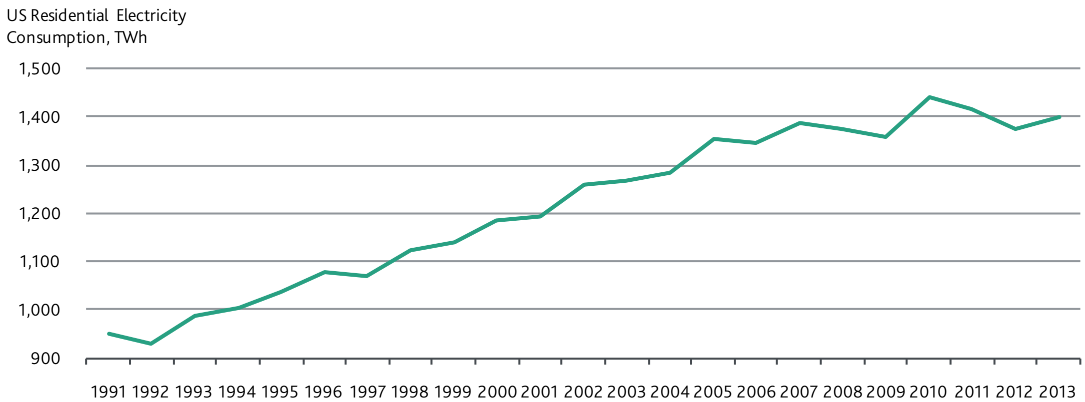
Notes: TWh stands for terawatt hour. 2013 US Energy Information Administration (EIA) data are through October 2013. Our estimates for November and December 2013 are based on historical trends.
Source: US Energy Information Administration

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

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Key Credit Factors For The Regulated Utilities Industry

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Key Credit Factors For The Regulated Utilities Industry

*(**Editor's Note:** This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.

2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," Dec. 9, 2010).

SUMMARY OF THE CRITERIA

4. Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage

assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

IMPACT ON OUTSTANDING RATINGS

5. These criteria could affect the issuer credit ratings of about 5% of regulated utilities globally due primarily to the introduction of new financial benchmarks in the corporate criteria. Almost all ratings changes are expected to be no more than one notch, and most are expected to be in an upward direction.

EFFECTIVE DATE AND TRANSITION

6. These criteria are effective immediately on the date of publication.

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11. We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15. As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

18. The analysis of competitive position includes a review of:

- Competitive advantage,
- Scale, scope, and diversity,
- Operating efficiency, and
- Profitability.

19. In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

24. Regulatory stability:

- Transparency of the key components of the rate setting and how these are assessed
- Predictability that lowers uncertainty for the utility and its stakeholders
- Consistency in the regulatory framework over time

25. Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

26. Financial stability:

- Timeliness of cost recovery to avoid cash flow volatility
- Flexibility to allow for recovery of unexpected costs if they arise
- Attractiveness of the framework to attract long-term capital
- Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

27. Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments. and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)		
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e.,

extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37. The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41. In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if

operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,
- Return on capital (ROC), and
- Return on equity (ROE).

49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least

seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)

58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio.The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is

employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

66. Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- Analytically determined risk factor.

- Calculations:
- Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the

debt.

- An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).

- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69. For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

71. Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.

- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume

that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.

- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;

- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Appendix--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

RELATED CRITERIA AND RESEARCH

- 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
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Belmont Municipal Light Department, *et al.*	)	
v.	)	**Docket No. EL16-64-002**
	)	
Central Maine Power Company, *et al.*	)	

AFFIDAVIT OF ADRIEN M. MCKENZIE

Adrien M. McKenzie, being first duly sworn, deposes and says that he is the Adrien M. McKenzie referred to in the foregoing testimony, that he has read such testimony and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

Adrien M. McKenzie

Subscribed and sworn to before me this ____ day of November, 2017, by Adrien M. McKenzie, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Notary Public

Commission Expires on: 01/31/2021

TYSHA L. JOHNSON
Notary Public, State of Texas
Expires 01/31/2021
I.D.# 13098808

MOODY'S
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SECTOR IN-DEPTH
10 MARCH 2015

Rate this Research

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US Regulated Utilities

Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles

The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinise their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures. Regulators can also adjust a utility's equity capitalization in its rate base. All else being equal, we think most utilities would prefer a thicker equity base and a lower authorized ROE over a small equity layer and a high authorized ROE.

» **More timely cost recovery helps offset falling ROEs**. Regulators continue to permit a robust suite of mechanisms that enable utilities to recoup prudently incurred operating costs, including capital investments such as environment related or infrastructure hardening expenditures. Strong cost recovery is credit positive because it ensures a stable financial profile. Despite lower authorized ROEs, we see the sector maintaining a ratio of Funds From Operations (FFO) to debt near 20%, a level that continues to support strong investment-grade ratings.

» **Utilities' cash flow is somewhat insulated from lower ROEs**. Net income represents about 30% - 40% of utilities' cash flow, so lower authorized returns won't necessarily affect cash flow or key financial credit ratios, especially when the denominator (equity) is rising. Regulators set the equity layer when capitalizing rate base, and the equity layer multiplied by the authorized ROE drives the annual revenue requirements. Across the sector, the ratio of equity to total assets has remained flat in the 30% range since 2007.

» **Utilities' actual financial performance remains stable**. Earned ROEs, which typically lag authorized ROEs, have not fallen as much as authorized returns in recent years. Since 2007, vertically integrated utilities, transmission and distribution only utilities, and natural gas local distribution companies have maintained steady earned ROE's in the 9% - 10% range. Holding companies with primarily regulated businesses also earned ROEs of around 9% - 10%, while returns for holding companies with diversified operations, namely unregulated generation, have fallen from 11% (over the past seven year average) to around 9% today.

Robust Suite of Cost Recovery Mechanisms Is Credit Positive

Over the past few years, the US regulatory environment has been very supportive of utilities. We think this is partly because regulators acknowledge that utility infrastructure needs a material amount of ongoing investment for maintenance, refurbishment and renovation. Utilities have also been able to garner support from both politicians and regulators for prudent investment in these critical assets because it helps create jobs, spurring economic growth. We also think regulators prefer to regulate financially healthy utilities.

Across the US, we continue to see regulators approving mechanisms that allow for more timely recovery of costs, a material credit positive. These mechanisms, which keep utilities' business risk profile low compared to most industrial corporate sectors, include: formulaic rate structures; special purpose trackers or riders; decoupling programs (which delink volumes from revenue); the use of future test years or other pre-approval arrangements. We also see a sustained increase in the frequency of rate case filings.

A supportive regulatory environment translates into a more transparent and stable financial profile, which in turn results in reasonably unfettered access to capital markets - for both debt and equity. Today, we think utilities enjoy an attractive set of market conditions that will remain in place over the next few years. By themselves, neither a slow (but steady) decline in authorized profitability, nor a material revision in equity market valuation multiples, will derail the stable credit profile of US regulated utilities.

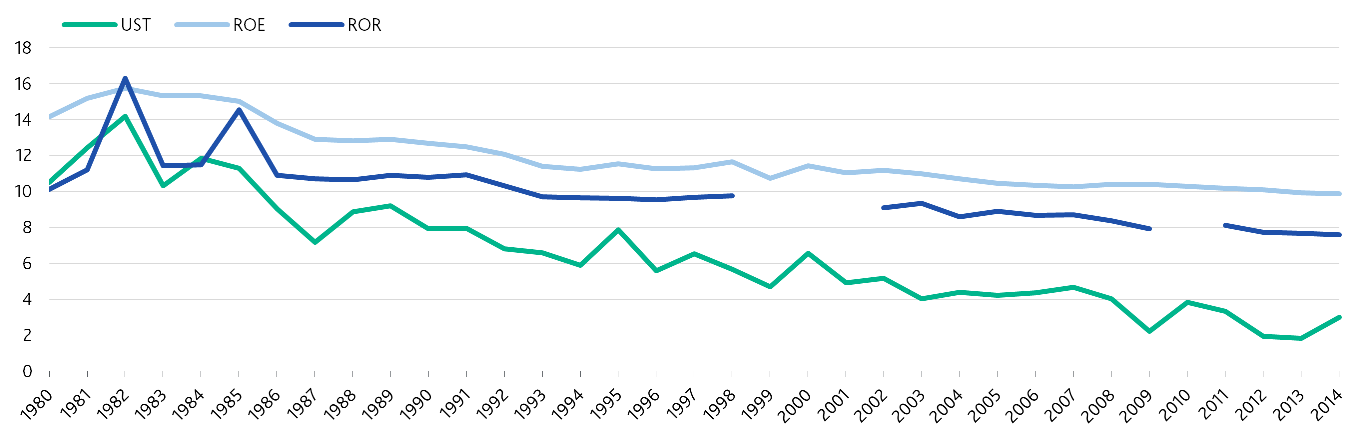
Cost recovery will help offset falling ROEs

Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

In the table below, we show the US Treasury 10-year yield, which has steadily fallen from the 5% range in the summer of 2007 to the 2% range today. US utilities benefit from these lower interest rates because they borrow approximately $50 billion a year. For some utilities, a lower cost of debt translates directly into a higher return on equity, as long as their rate structure includes an embedded weighted average cost of capital (and the utilities can stay out of a general rate case proceeding).

Exhibit 1

Regulators hold up their end of the bargain by limiting reduction in return on equity (ROE) and overall rate of return (ROR) when compared with the decline in US Treasury 10-year yields



SOURCE: SNL Financial, LP, Moody's

As utilities increasingly secure more up-front assurance for cost recovery in their rate proceedings, we think regulators will increasingly view the sector as less risky. The combination of low capital costs, high equity market valuation multiples (which are better than or on par with the broader market despite the regulated utilities' low risk profile), and a transparent assurance of cost recovery tend to support the case for lower authorized returns, although because utilities will argue they should rise, or at least stay unchanged.

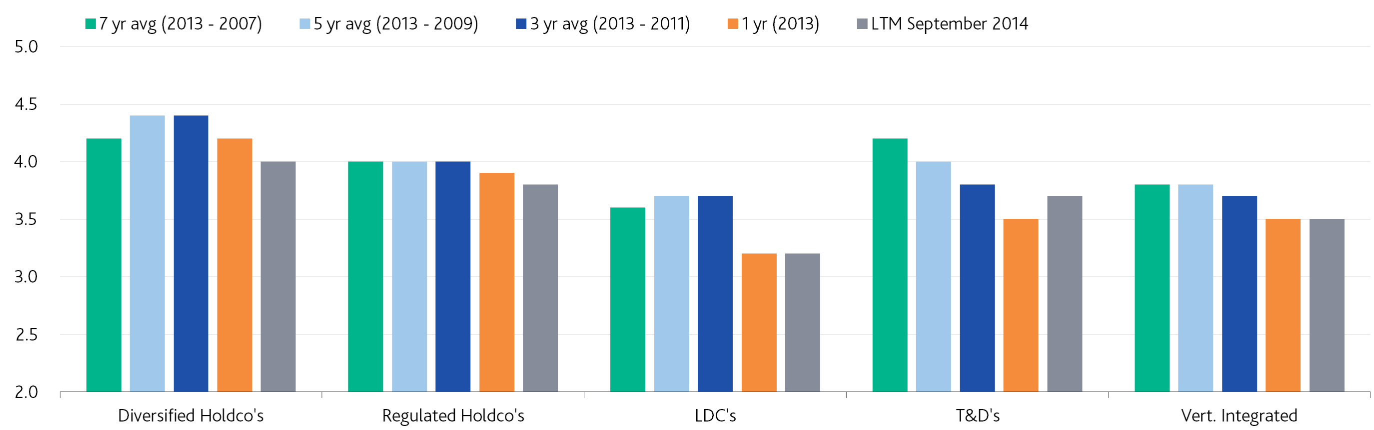
One of the arguments for keeping authorized ROEs steady is that lowering them would make utilities less attractive to providers of capital. Utility holding companies assert that they would rather invest in higher risk-adjusted opportunities than in a regulated utility with sub-par return prospects. We see a risk that this argument could lead to a more contentious regulatory environment, a material credit negative. We do not think this scenario will develop over the next few years.

Our default and recovery data provides strong evidence that regulated utilities are indeed less risky (from the perspective of a probability of default and expected loss given default, as defined by Moody's) than their non-financial corporate peers. On a global basis, we nonetheless see a material amount of capital looking for regulated utility investment opportunities, and the same is true in the US despite, despite a lower authorized return. This is partly because investors can use holding company leverage to increase their actual equity returns, by borrowing capital at today's low interest rates and investing in the equity of a regulated utility.

Despite the reduction in authorized ROEs, US utilities are thankful to their regulators for the robust suite of timely cost recovery mechanisms which allow them to recoup prudently incurred operating costs such as fuel, as well as some investment expenses. These recovery mechanisms drive a stable and transparent dividend policy, which translates into historically very high equity multiples. Moreover, cost recovery helps keep the sector's overall financial profile stable, thereby supporting strong investment-grade ratings.

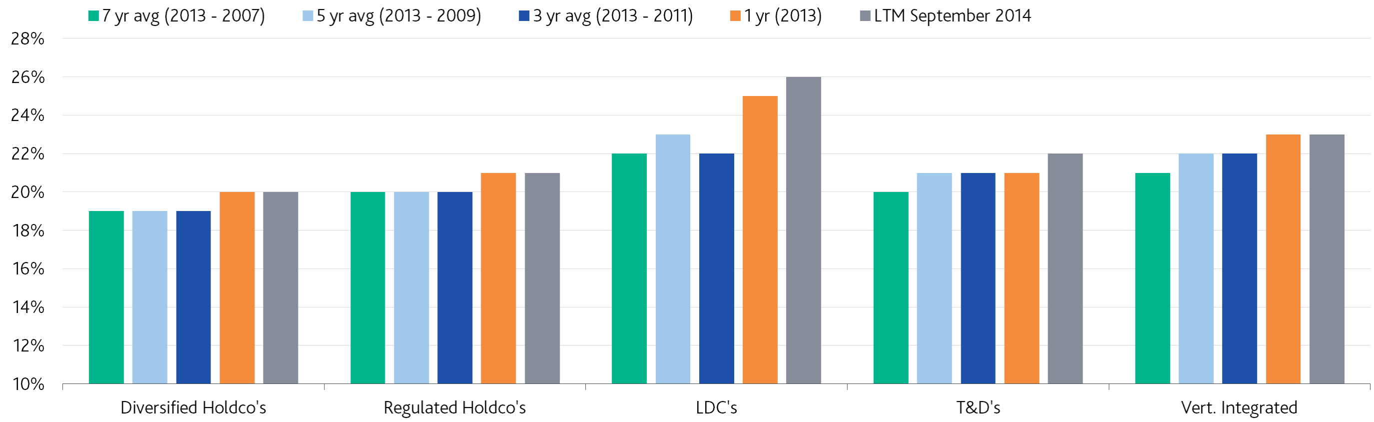
Exhibit 2

With better recovery mechanisms, the ratio of debt-to-EBITDA can rise, modestly, without negatively impacting credit profiles



SOURCE: Company filings; Moody's

Exhibit 3
The ratio of Funds From Operations to debt is rising, a material credit positive,
but the rise is partly funded by bonus depreciation and deferred taxes, which will eventually reverse



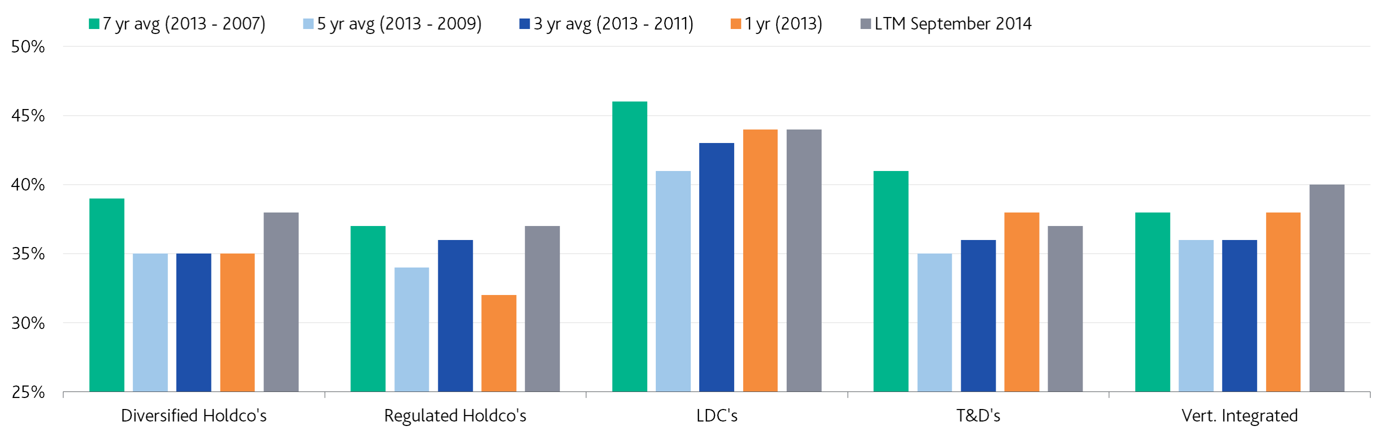
SOURCE: Company filings; Moody's

Utilities' cash flow is somewhat insulated from declining ROEs

Across all our utility group sub-sectors (see Appendix), net income - the numerator in the calculation of ROE – accounts for between 30% - 40% of cash flow. While net income is important, cash flow exerts a much greater influence over creditworthiness. This is primarily because cash flow takes into account depreciation and amortization expenses, along with other deferred tax adjustments. We note that deferred taxes have risen over the past few years, in part due to bonus depreciation elections, which will eventually reverse. From a credit perspective, there is a difference between the nominal amount of net income, which goes into cash flow, and the relationship of net income to book equity (a measure of profitability).

In the chart below, we highlight the ratio of net income to cash flow from operations (CFO) for our selected peer groups. Across all of the sectors, the longer term historical average of net income to CFO has fallen compared with the late 2000s, but has been rising over the more recent past. This is partly a function of deferred taxes, which have become a larger component of CFO over the past decade.

Exhibit 4
Net income as a % of cash flow from operations has been steadily rising (since 2011)

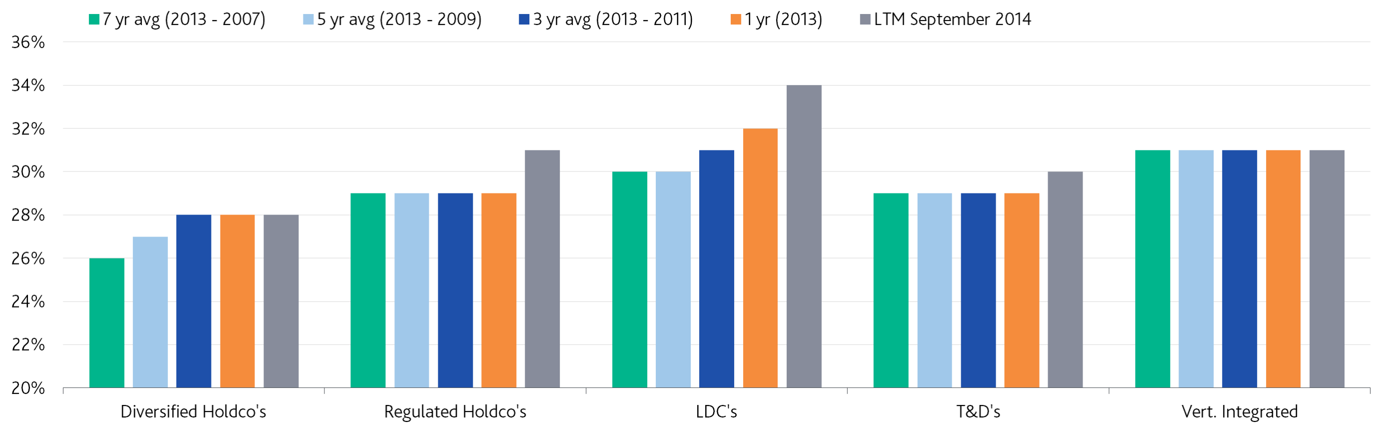


SOURCE: Company filings, Moody's

We can also envisage scenarios where regulators seek to achieve a reduction in authorized ROEs without harming credit profiles by focusing on utilities' equity layer. In the chart below, we illustrate median equity as a percentage of total assets for our selected peer groups. In our illustration, utilities will benefit from acquisition related goodwill on one hand, and impairments on the other.

Exhibit 5

Equity as a % of total assets, not capitalization, includes both goodwill and impairments



SOURCE: Company filings; Moody's

Utilities' actual financial performance remains stable

Earned ROE's, as reported by utilities and adjusted by Moody's, have been relatively flat over the past few years, despite the decline in authorized ROEs. This means utilities are closer to earning their authorized equity returns, which is positive from an equity market valuation perspective.

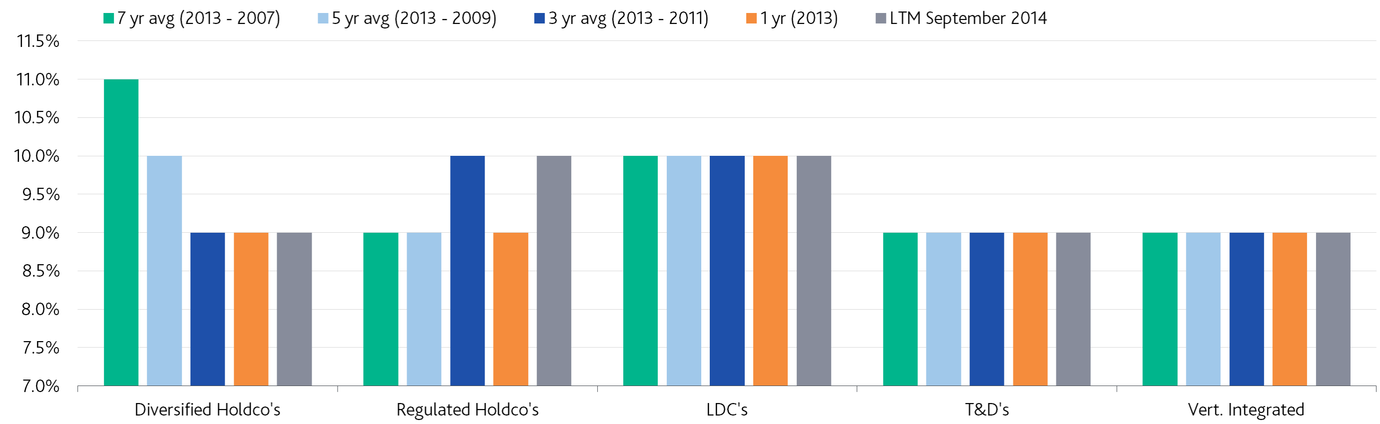
The authorized ROE is a popular focal point in many regulatory rate case proceedings. In addition, many regulatory jurisdictions look to established precedents that rely on various methodologies to determine an appropriate ROE, such as the capital asset pricing model or discounted cash flow analysis. In some jurisdictions where formulaic based rate structures point to lower ROEs for a longer projected period of time, regulators are incorporating a view that today's interest rate environment is "artificially" being held low.

Regardless, we think interest rates will go up, eventually. When they do, we also think authorized ROEs will trend up as well. However, just as authorized ROEs declined in a lagging fashion when compared to falling interest rates, we expect authorized ROEs to rise in a lagging fashion when interest rates rise.

Depending on alternative sources of risk-adjusted capital investment opportunities, this could spell trouble for utilities. For now, utilities can enjoy their (historically) high equity valuations, in terms of dividend yield and price-earnings ratios.

Exhibit 6

GAAP adjusted earned ROE's are relatively flat across all sub-sectors except Holding Companies with Diversified Operations, while the lower-risk LDC sector is outperforming



NOTE: GAAP adjusted ROE, not regulated ROE, does not adjust for goodwill or impairments.

Source: Company filings; Moody's

Appendix

Exhibit 7

Utilities with the highest earned ROEs (ranked by 7-year average)

Company Name	Sector	Rating	1-year average (2013) ROE	3-year average (2013 - 2011) ROE	5-year average (2013 - 2009) ROE	7-year average (2013 - 2007) ROE
CenterPoint Energy Houston Electric, LLC	T&D	A3	33%	32%	25%	23%
Questar Corporation	Holdco - Primarily Regulated	A2	14%	18%	20%	20%
AEP Texas Central Company	T&D	Baa1	14%	28%	22%	20%
Exelon Corporation	Holdco - Diversified	Baa2	7%	10%	14%	17%
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1	7%	16%	15%	17%
Ohio Edison Company	T&D	Baa1	23%	18%	17%	16%
Public Service Enterprise Group	Holdco - Diversified	Baa2	11%	12%	14%	15%
Dayton Power & Light Company	T&D	Baa3	7%	9%	13%	15%
Dominion Resources Inc.	Holdco - Diversified	Baa2	13%	9%	12%	15%
Southern California Gas Company	LDC	A1	14%	13%	14%	15%
PECO Energy Company	T&D	A2	12%	12%	12%	14%
PPL Corporation	Holdco - Diversified	Baa3	9%	12%	11%	14%
UGI Utilities, Inc.	LDC	A2	15%	13%	13%	13%
Entergy Corporation	Holdco - Diversified	Baa3	7%	11%	12%	13%
Cleco Corporation	Holdco - Primarily Regulated	Baa1	10%	12%	13%	13%
Alabama Gas Corporation	LDC	A2	4%	11%	12%	13%
Entergy New Orleans, Inc.	Vertically Integrated Utility	Ba2	5%	10%	11%	12%
Entergy Gulf States Louisiana, LLC	Vertically Integrated Utility	Baa1	11%	13%	12%	12%
Piedmont Natural Gas Company, Inc.	LDC	A2	11%	11%	12%	12%
Ohio Power Company	T&D	Baa1	25%	14%	13%	12%
Southern Company (The)	Holdco - Primarily Regulated	Baa1	9%	11%	11%	12%
Georgia Power Company	Vertically Integrated Utility	A3	12%	12%	12%	12%
Alabama Power Company	Vertically Integrated Utility	A1	12%	12%	12%	12%
Southern California Edison Company	Vertically Integrated Utility	A2	8%	12%	12%	12%
NextEra Energy, Inc.	Holdco - Diversified	Baa1	10%	11%	11%	12%
Wisconsin Energy Corporation	Holdco - Primarily Regulated	A2	13%	13%	12%	12%
West Penn Power Company	T&D	Baa1	17%	13%	12%	12%
San Diego Gas & Electric Company	Vertically Integrated Utility	A1	9%	10%	11%	12%
Interstate Power and Light Company	Vertically Integrated Utility	A3	10%	9%	9%	12%

NOTE: GAAP adjusted ROE, not regulated ROE, does not adjust for goodwill or impairments.

SOURCE: Moody's; company filings

Exhibit 8

Highest (over 30%) and lowest (less than 20%) equity level as a % of total assets (ranked by 7-year average) [NOTE: Book equity is not adjusted for goodwill or impairments]

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Duke Energy Ohio, Inc.	T&D	Baa1	48%	47%	48%	50%
Yankee Gas Services Company	LDC	Baa1	41%	42%	43%	43%
Texas-New Mexico Power Company	T&D	Baa1	43%	43%	43%	43%
Oncor Electric Delivery Company LLC	T&D	Baa1	40%	41%	41%	43%
Dayton Power & Light Company	T&D	Baa3	37%	38%	39%	40%
Pennsylvania Power Company	T&D	Baa1	25%	30%	34%	40%
Black Hills Power, Inc.	Vertically Integrated Utility	A3	38%	38%	37%	38%
ALLETE, Inc.	Vertically Integrated Utility	A3	38%	37%	37%	38%
Central Maine Power Company	T&D	A3	39%	38%	38%	38%
MGE Energy, Inc.	Holdco - Primarily Regulated	NR	39%	37%	38%	38%
Duke Energy Corporation	Holdco - Primarily Regulated	A3	36%	36%	37%	38%
Jersey Central Power & Light Company	T&D	Baa2	32%	33%	36%	38%
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1	36%	37%	37%	37%
Public Service Company of Colorado	Vertically Integrated Utility	A3	37%	37%	37%	37%
Virginia Electric and Power Company	Vertically Integrated Utility	A2	37%	37%	37%	35%
Wisconsin Public Service Corporation	Vertically Integrated Utility	A1	34%	34%	34%	35%
PacifiCorp	Vertically Integrated Utility	A3	36%	35%	35%	35%
UGI Utilities, Inc.	LDC	A2	35%	34%	34%	34%
Cleco Corporation	Holdco - Primarily Regulated	Baa1	37%	36%	34%	34%
Empire District Electric Company (The)	Vertically Integrated Utility	Baa1	35%	34%	34%	34%
Great Plains Energy Incorporated	Holdco - Primarily Regulated	Baa2	35%	35%	34%	34%
Nevada Power Company	Vertically Integrated Utility	Baa1	32%	33%	33%	33%
Tampa Electric Company	Vertically Integrated Utility	A2	34%	33%	33%	33%
Wisconsin Power and Light Company	Vertically Integrated Utility	A1	34%	33%	32%	33%
Questar Corporation	Holdco - Primarily Regulated	A2	29%	28%	31%	33%
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1	31%	30%	33%	33%
Florida Power & Light Company	Vertically Integrated Utility	A1	36%	35%	34%	33%
Alabama Gas Corporation	LDC	A2	59%	40%	35%	33%
El Paso Electric Company	Vertically Integrated Utility	Baa1	34%	32%	32%	33%
IDACORP, Inc.	Holdco - Primarily Regulated	Baa1	34%	33%	33%	33%
PPL Electric Utilities Corporation	Vertically Integrated Utility	Baa1	34%	34%	34%	33%
Commonwealth Edison Company	T&D	Baa1	31%	32%	32%	33%
Georgia Power Company	Vertically Integrated Utility	A3	33%	33%	33%	33%
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2	20%	19%	18%	18%
Hawaiian Electric Industries, Inc.	Holdco - Diversified		17%	16%	16%	16%
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1	20%	19%	17%	15%
CenterPoint Energy Houston Electric, LLC	T&D	A3	9%	15%	15%	15%
AEP Texas Central Company	T&D	Baa1	13%	15%	14%	13%

SOURCE: Moody's; company filings

Exhibit 9

Highest (over 30%) and lowest (less than 15%) ratio of FFO to debt (ranked by 7-year average)

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Dayton Power & Light Company	T&D	Baa3	32%	34%	42%	42%
Questar Corporation	Holdco - Primarily Regulated	A2	29%	30%	31%	42%
Pennsylvania Power Company	T&D	Baa1	30%	34%	32%	37%
Exelon Corporation	Holdco - Diversified	Baa2	28%	34%	37%	37%
Alabama Gas Corporation	LDC	A2	23%	27%	32%	36%
Florida Power & Light Company	Vertically Integrated Utility	A1	34%	35%	35%	35%
Southern California Gas Company	LDC	A1	42%	37%	35%	34%
Southern California Edison Company	Vertically Integrated Utility	A2	32%	33%	35%	32%
Madison Gas and Electric Company	Vertically Integrated Utility	A1	39%	35%	34%	31%
PECO Energy Company	T&D	A2	29%	31%	33%	31%
Dominion Resources Inc.	Holdco - Diversified	Baa2	16%	17%	16%	14%
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3	15%	14%	12%	14%
Monongahela Power Company	T&D	Baa2	13%	16%	15%	14%
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2	18%	16%	15%	14%
Appalachian Power Company	Vertically Integrated Utility	Baa1	15%	13%	14%	14%
Pennsylvania Electric Company	T&D	Baa2	15%	14%	12%	13%
NiSource Inc.	Holdco - Diversified	Baa2	15%	14%	14%	13%
Puget Energy, Inc.	Vertically Integrated Utility	Baa3	14%	12%	12%	13%
Toledo Edison Company	T&D	Baa3	10%	10%	8%	13%
Cleveland Electric Illuminating Company	T&D	Baa3	11%	11%	12%	13%
AEP Texas Central Company	T&D	Baa1	14%	15%	13%	12%

SOURCE: Moody's; company filings

Exhibit 10

Highest (over 4.5x) and lowest (less than 3.0x) ratio of debt to EBITDA (ranked by 1-year average, 2013, to focus on more recent performance)

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Berkshire Hathaway Energy Company	Holdco - Diversified	A3	7.1	5.8	5.6	5.3
FirstEnergy Corp.	Holdco - Diversified	Baa3	6.0	5.2	4.8	4.4
Wisconsin Electric Power Company	Vertically Integrated Utility	A1	5.9	6.1	5.6	5.0
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3	5.8	6.1	6.2	6.1
Monongahela Power Company	T&D	Baa2	5.6	5.2	5.7	6.0
NiSource Inc.	Holdco - Diversified	Baa2	5.2	5.5	5.4	5.5
PPL Corporation	Holdco - Diversified	Baa3	5.1	4.9	5.1	4.6
Appalachian Power Company	Vertically Integrated Utility	Baa1	5.0	5.0	5.2	5.4
Progress Energy, Inc.	Holdco - Primarily Regulated	Baa1	4.9	5.6	5.1	4.9
Puget Energy, Inc.	Vertically Integrated Utility	Baa3	4.9	5.6	5.9	5.6
Cleveland Electric Illuminating Company	T&D	Baa3	4.9	5.2	4.7	4.2
Northwest Natural Gas Company	LDC	A3	4.8	4.8	4.5	4.2
Jersey Central Power & Light Company	T&D	Baa2	4.7	5.5	4.2	3.6
NorthWestern Corporation	Vertically Integrated Utility	A3	4.7	4.5	4.4	4.3
Pepco Holdings, Inc.	Holdco - Primarily Regulated	Baa3	4.7	5.1	5.2	5.2
Laclede Gas Company	LDC	A3	4.7	5.5	5.3	5.6
Atlantic City Electric Company	T&D	Baa2	4.7	4.9	4.8	4.7
Nevada Power Company	Vertically Integrated Utility	Baa1	4.6	4.6	4.9	5.0
Black Hills Power, Inc.	Vertically Integrated Utility	A3	2.9	3.2	3.8	3.6
Virginia Electric and Power Company	Vertically Integrated Utility	A2	2.9	3.1	3.4	3.4
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1	2.9	3.3	3.3	3.4
Texas-New Mexico Power Company	T&D	Baa1	2.9	2.9	3.2	3.3
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1	2.9	2.9	2.9	3.0
Cleco Power LLC	Vertically Integrated Utility	A3	2.9	3.2	3.6	3.7
Consumers Energy Company	Vertically Integrated Utility	A1	2.9	3.1	3.3	3.5
Alabama Power Company	Vertically Integrated Utility	A1	2.8	2.9	3.0	3.1
Public Service Electric and Gas Company	T&D	A2	2.8	3.0	3.2	3.3
Alabama Gas Corporation	LDC	A2	2.8	2.7	2.5	2.4
Pinnacle West Capital Corporation	Holdco - Primarily Regulated	Baa1	2.8	3.1	3.3	3.6
Cleco Corporation	Holdco - Primarily Regulated	Baa1	2.8	2.9	3.4	3.6
PECO Energy Company	T&D	A2	2.8	3.0	2.6	2.6
Northern States Power Company (Wisconsin)	Vertically Integrated Utility	A2	2.8	2.9	2.8	2.8
Duke Energy Carolinas, LLC	Vertically Integrated Utility	A1	2.8	3.1	3.2	3.1
UGI Utilities, Inc.	LDC	A2	2.7	3.0	3.1	3.3
Exelon Corporation	Holdco - Diversified	Baa2	2.7	2.8	2.5	2.5
West Penn Power Company	T&D	Baa1	2.7	3.3	3.3	3.4
Questar Corporation	Holdco - Primarily Regulated	A2	2.7	2.8	2.7	2.3
Tampa Electric Company	Vertically Integrated Utility	A2	2.6	2.7	2.8	2.9
Arizona Public Service Company	Vertically Integrated Utility	A3	2.6	2.9	3.1	3.3
New York State Electric and Gas Corporation	T&D	A3	2.6	2.9	3.2	4.3
Dayton Power & Light Company	T&D	Baa3	2.5	2.2	2.0	1.9
Florida Power & Light Company	Vertically Integrated Utility	A1	2.4	2.7	2.6	2.6
Ohio Power Company	T&D	Baa1	2.4	2.8	3.1	3.3
Madison Gas and Electric Company	Vertically Integrated Utility	A1	2.4	2.8	2.8	2.9
Pennsylvania Power Company	T&D	Baa1	2.4	2.3	2.4	2.2
MGE Energy, Inc.	Holdco - Primarily Regulated	NR	2.3	2.7	2.9	3.1
Rochester Gas & Electric Corporation	T&D	Baa1	2.3	2.9	3.0	3.5
Public Service Enterprise Group Incorporated	Holdco - Diversified	Baa2	2.3	2.3	2.3	2.4
NSTAR Electric Company	T&D	A2	2.2	2.6	2.7	2.8
Southern California Gas Company	LDC	A1	2.2	2.5	2.4	2.5
Mississippi Power Company	Vertically Integrated Utility	Baa1	(3.2)	3.5	3.4	3.1

Exhibit 11

List of Companies (NOTE: in our appendix tables, we exclude utilities with private ratings)

Company Name	Sector	Rating
Berkshire Hathaway Energy Company	Holdco - Diversified	A3
Black Hills Corporation	Holdco - Diversified	Baa1
Dominion Resources Inc.	Holdco - Diversified	Baa2
DTE Energy Company	Holdco - Diversified	A3
Entergy Corporation	Holdco - Diversified	Baa3
Exelon Corporation	Holdco - Diversified	Baa2
FirstEnergy Corp.	Holdco - Diversified	Baa3
Hawaiian Electric Industries, Inc.	Holdco - Diversified	NR
Integrys Energy Group, Inc.	Holdco - Diversified	A3
NextEra Energy, Inc.	Holdco - Diversified	Baa1
NiSource Inc.	Holdco - Diversified	Baa2
PPL Corporation	Holdco - Diversified	Baa3
Public Service Enterprise Group Incorporated	Holdco - Diversified	Baa2
Sempra Energy	Holdco - Diversified	Baa1
Alliant Energy Corporation	Holdco - Primarily Regulated	A3
Ameren Corporation	Holdco - Primarily Regulated	Baa2
American Electric Power Company, Inc.	Holdco - Primarily Regulated	Baa1
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1
Cleco Corporation	Holdco - Primarily Regulated	Baa1
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2
Consolidated Edison, Inc.	Holdco - Primarily Regulated	A3
Duke Energy Corporation	Holdco - Primarily Regulated	A3
Edison International	Holdco - Primarily Regulated	A3
Great Plains Energy Incorporated	Holdco - Primarily Regulated	Baa2
IDACORP, Inc.	Holdco - Primarily Regulated	Baa1
MGE Energy, Inc.	Holdco - Primarily Regulated	NR
Northeast Utilities	Holdco - Primarily Regulated	Baa1
Pepco Holdings, Inc.	Holdco - Primarily Regulated	Baa3
PG&E Corporation	Holdco - Primarily Regulated	Baa1
Pinnacle West Capital Corporation	Holdco - Primarily Regulated	Baa1
PNM Resources, Inc.	Holdco - Primarily Regulated	Baa3
Progress Energy, Inc.	Holdco - Primarily Regulated	Baa1
Questar Corporation	Holdco - Primarily Regulated	A2
SCANA Corporation	Holdco - Primarily Regulated	Baa3
Southern Company (The)	Holdco - Primarily Regulated	Baa1
Wisconsin Energy Corporation	Holdco - Primarily Regulated	A2
Xcel Energy Inc.	Holdco - Primarily Regulated	A3
Alabama Gas Corporation	LDC	A2
Atmos Energy Corporation	LDC	A2
DTE Gas Company	LDC	Aa3
Laclede Gas Company	LDC	A3
New Jersey Natural Gas Company	LDC	Aa2
Northern Natural Gas Company [Private]	LDC	A2
Northwest Natural Gas Company	LDC	A3
Piedmont Natural Gas Company, Inc.	LDC	A2
South Jersey Gas Company	LDC	A2
Southern California Gas Company	LDC	A1
Southwest Gas Corporation	LDC	A3
UGI Utilities, Inc.	LDC	A2
Washington Gas Light Company	LDC	A1
Wisconsin Gas LLC [Private]	LDC	A1
Yankee Gas Services Company	LDC	Baa1
AEP Texas Central Company	T&D	Baa1
AEP Texas North Company	T&D	Baa1
Atlantic City Electric Company	T&D	Baa2

Baltimore Gas and Electric Company	T&D	A3
CenterPoint Energy Houston Electric, LLC	T&D	A3
Central Hudson Gas & Electric Corporation	T&D	A2
Central Maine Power Company	T&D	A3
Cleveland Electric Illuminating Company (The)	T&D	Baa3
Commonwealth Edison Company	T&D	Baa1
Connecticut Light and Power Company	T&D	Baa1
Consolidated Edison Company of New York, Inc.	T&D	A2
Dayton Power & Light Company	T&D	Baa3
Delmarva Power & Light Company	T&D	Baa1
Duke Energy Ohio, Inc.	T&D	Baa1
Jersey Central Power & Light Company	T&D	Baa2
Metropolitan Edison Company	T&D	Baa1
Monongahela Power Company	T&D	Baa2
New York State Electric and Gas Corporation	T&D	A3
NSTAR Electric Company	T&D	A2
Ohio Edison Company	T&D	Baa1
Ohio Power Company	T&D	Baa1
Oncor Electric Delivery Company LLC	T&D	Baa1
Orange and Rockland Utilities, Inc.	T&D	A3
PECO Energy Company	T&D	A2
Pennsylvania Electric Company	T&D	Baa2
Pennsylvania Power Company	T&D	Baa1
Potomac Edison Company (The)	T&D	Baa2
Potomac Electric Power Company	T&D	Baa1
Public Service Electric and Gas Company	T&D	A2
Rochester Gas & Electric Corporation	T&D	Baa1
Texas-New Mexico Power Company	T&D	Baa1
Toledo Edison Company	T&D	Baa3
West Penn Power Company	T&D	Baa1
Western Massachusetts Electric Company	T&D	A3
Alabama Power Company	Vertically Integrated Utility	A1
ALLETE, Inc.	Vertically Integrated Utility	A3
Appalachian Power Company	Vertically Integrated Utility	Baa1
Arizona Public Service Company	Vertically Integrated Utility	A3
Avista Corp.	Vertically Integrated Utility	Baa1
Black Hills Power, Inc.	Vertically Integrated Utility	A3
Cleco Power LLC	Vertically Integrated Utility	A3
Consumers Energy Company	Vertically Integrated Utility	A1
DTE Electric Company	Vertically Integrated Utility	A2
Duke Energy Carolinas, LLC	Vertically Integrated Utility	A1
Duke Energy Florida, Inc.	Vertically Integrated Utility	A3
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1
Duke Energy Progress, Inc.	Vertically Integrated Utility	A1
El Paso Electric Company	Vertically Integrated Utility	Baa1
Empire District Electric Company (The)	Vertically Integrated Utility	Baa1
Entergy Arkansas, Inc.	Vertically Integrated Utility	Baa2
Entergy Gulf States Louisiana, LLC	Vertically Integrated Utility	Baa1
Entergy Louisiana, LLC	Vertically Integrated Utility	Baa1
Entergy Mississippi, Inc.	Vertically Integrated Utility	Baa2
Entergy New Orleans, Inc.	Vertically Integrated Utility	Ba2
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3
Florida Power & Light Company	Vertically Integrated Utility	A1
Georgia Power Company	Vertically Integrated Utility	A3
Gulf Power Company	Vertically Integrated Utility	A2
Hawaiian Electric Company, Inc.	Vertically Integrated Utility	Baa1
Idaho Power Company	Vertically Integrated Utility	A3
Indiana Michigan Power Company	Vertically Integrated Utility	Baa1
Interstate Power and Light Company	Vertically Integrated Utility	A3
Kansas City Power & Light Company	Vertically Integrated Utility	Baa1
Kentucky Power Company	Vertically Integrated Utility	Baa2

Madison Gas and Electric Company	Vertically Integrated Utility	A1
MidAmerican Energy Company	Vertically Integrated Utility	A1
Mississippi Power Company	Vertically Integrated Utility	Baa1
Nevada Power Company	Vertically Integrated Utility	Baa1
Northern States Power Company (Minnesota)	Vertically Integrated Utility	A2
Northern States Power Company (Wisconsin)	Vertically Integrated Utility	A2
NorthWestern Corporation	Vertically Integrated Utility	A3
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1
Pacific Gas & Electric Company	Vertically Integrated Utility	A3
PacifiCorp	Vertically Integrated Utility	A3
Portland General Electric Company	Vertically Integrated Utility	A3
PPL Electric Utilities Corporation	Vertically Integrated Utility	Baa1
Public Service Company of Colorado	Vertically Integrated Utility	A3
Public Service Company of New Hampshire	Vertically Integrated Utility	Baa1
Public Service Company of New Mexico	Vertically Integrated Utility	Baa2
Public Service Company of Oklahoma	Vertically Integrated Utility	A3
Puget Energy, Inc.	Vertically Integrated Utility	Baa3
Puget Sound Energy, Inc.	Vertically Integrated Utility	Baa1
San Diego Gas & Electric Company	Vertically Integrated Utility	A1
Sierra Pacific Power Company	Vertically Integrated Utility	Baa1
South Carolina Electric & Gas Company	Vertically Integrated Utility	Baa2
Southern California Edison Company	Vertically Integrated Utility	A2
Southwestern Electric Power Company	Vertically Integrated Utility	Baa2
Southwestern Public Service Company	Vertically Integrated Utility	Baa1
Tampa Electric Company	Vertically Integrated Utility	A2
Tucson Electric Power Company	Vertically Integrated Utility	Baa1
Union Electric Company	Vertically Integrated Utility	Baa1
Virginia Electric and Power Company	Vertically Integrated Utility	A2
Wisconsin Electric Power Company	Vertically Integrated Utility	A1
Wisconsin Power and Light Company	Vertically Integrated Utility	A1
Wisconsin Public Service Corporation	Vertically Integrated Utility	A1

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A Study of Financial Analysts: Practice and Theory

Stanley B. Block

The study reported here focused on determining what analytical techniques financial analysts who are members of AIMR actually use. The study achieved a response rate of 33.75 percent. Questions covered 16 areas, including the use of present value analysis, the importance of quarterly earnings' announcements in decision making, belief in efficient markets, acceptance or rejection of market anomalies, and belief in the importance of international diversification for risk reduction.

The exams, curriculum materials, and seminars designed for the CFA® (Chartered Financial Analyst) Program are based on knowing what is important to practicing financial analysts. Yet, little documentation exists about what financial analysts actually believe in and do. The intent of this research was not necessarily to identify the normative approaches but, rather, to identify the most widely used approaches. Moreover, the results are not intended to suggest that future analysts be directed to the most commonly used approaches. The intention of this article is to share knowledge about what goes on in the day-to-day practice of financial analysts.

For example, use of present value analysis is heavily stressed in the CFA curriculum and is a major focus of textbooks on investments, but how widely is present value analysis actually used and by whom? Also, new techniques for analysis, such as economic value added, have received relatively less attention than traditional measures of analysis, but little is known about how widely accepted EVA is by practitioners. This survey addressed such issues.

The Study

The participants in this study came from the membership of AIMR (the Association for Investment Management and Research). Questionnaires were mailed to a random sample of 900 AIMR members in the United States in October 1998.[1] Because of address changes and other factors, 880 mailings successfully arrived at their intended destinations. Of that number, 297 usable responses were received, for a return ratio of 33.75 percent. A follow-up telephone survey of randomly selected nonrespondents indicated no statistically significant differences between those who initially answered the questionnaire and those who did not.

The final questionnaire, which is reproduced in Appendix A, had been previously tested in three pilot group surveys.

The questionnaire materials made clear to participants that the survey was sponsored by the author and not by any business organization or AIMR itself.[2]

The Respondent Group

The first three tables in this article reveal key characteristics of those who responded to the questionnaire. In **Table 1**, the 297 respondents are delineated by the type of firm for which they worked. The largest number of responding financial analysts were employed by brokerage firms and private money management groups. Investment management counseling firms, mutual funds, and bank trust departments are also represented substantially. Although no attempt was made in this study to stratify the sample by industry classification in advance, the composition of respondents does reasonably represent the membership profile by industry classification as reported by the more than 32,000 AIMR members in the *1998 Membership Directory*.[3]

As indicated in **Table 2**, 67.7 percent of the respondents were CFA charterholders and 53.9 percent held M.B.A. degrees. The charterholder number in this sample is slightly smaller than for the total organization (70 percent), whereas the M.B.A. degree number is slightly larger than for the

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Table 1. Respondent Breakdown by Industry Classification

Industry	Number	Percent
Brokerage	77	25.9
Private money management group	75	25.2
Investment management counseling	39	13.1
Mutual fund	39	13.1
Bank trust department	32	10.8
Investment banking	18	6.1
Other	12	4.1
Pension fund	5	1.7
Total	297	100.0

total membership (47 percent). Note that the average experience of the respondents is 15.3 years.

Table 3 reports the undergraduate majors of the respondents. A large percentage of the respondents (and perhaps, inferentially, a large percentage of AIMR members, although no industry data are available with which to compare these data) had undergraduate degrees in business and economics. The notion that the typical route to becoming a financial analyst is for an individual to get a liberal arts degree and then use that broad-based background to concentrate later on financial analysis is not supported by these data.

Table 2. Respondent Breakdown by Certification, Education, and Experience

Characteristic	Number	Percent
A. Certification		
Charterholder	201	67.7
Noncharterholder	96	32.3
Total	297	100.0
B. Highest degree		
M.B.A.	160	53.9
Master	4	1.3
Doctor of Jurisprudence (J.D.)	2	0.7
Bachelor	131	44.1
Total	297	100.0
C. Experience (years)		
0–5	30	
6–10	81	
11–15	78	
16–20	36	
21–25	18	
26–30	15	
More than 30	39	
Total	297	
Average	15.3 years	

The Results

This section contains discussion of the survey findings regarding the variables (or inputs to valuation) and tools financial analysts use in equity valuation, their attitudes toward issues important in portfolio management, and their attitudes toward market efficiency versus market anomalies.

Table 3. Respondent Breakdown by Type of Undergraduate Degree

Discipline	Number	Percent
Finance	96	32.3
Economics	76	25.6
General business	38	12.8
Accounting	29	9.8
Liberal arts	28	9.4
Math, science, engineering	17	5.7
Other (psychology, public affairs, etc.)	13	4.4
Total	297	100.0

Valuation Inputs. Respondents were asked about their use of several variables and tools in analyzing securities. Among the most important was present value (PV) analysis; others included corporate earnings and cash flow.

Present value. The use of PV analysis is a central theme in valuation theory. There is probably not a CFA exam preparation course being taught around the world or an investments course being offered at a university that does not include PV analysis techniques. But as Panel A of Table 4 indicates, only 15.2 percent of respondents always use PV analysis and for 45.7 percent, it is not part of their normal procedures. Apparently, practitioners split about 50/50 in their use of PV techniques.

Should this finding be taken as an indictment of the profession? Hardly. When faced with the reality of valuation in the marketplace, the task of projecting earnings, dividends, and a stock price into the future and determining an appropriate discount rate may be too fraught with uncertainty for analysts to rely on discounted cash flow (DCF) analysis in the determination of value. As noted financial economist Stewart Myers (1984) of the Massachusetts Institute of Technology has suggested, "DCF is sensible, and widely used, for valuing relatively safe stocks paying regular dividends, but DCF is not as helpful in valuing companies with significant growth opportunities" (pp. 126–137).

Nevertheless, because PV analysis is part of the foundation of finance, I decided to analyze its use by various categories of participants. Shown in Panels B and C of Table 4 are the use and nonuse of PV analysis by CFA charterholders (hereafter, simply "charterholders") versus noncharterholders and M.B.A.s versus non-M.B.A.s. Although the charterholder group indicated a slightly larger tendency to use PV analysis than the noncharterholder group, the difference is not statistically significant at any

Table 4. Use of PV Techniques

Answer	Numbers	Percent
A. Overall sample		
Always	45	15.2
Sometimes	116	39.1
Never	136	45.7
Total	297	100.0
B. Charterholders versus noncharterholders		
Charterholders		
Always	38	18.9
Sometimes	70	34.8
Never	93	46.3
Total	201	100.0
Noncharterholders		
Always	7	7.3
Sometimes	46	47.9
Never	43	44.8
Total	96	100.0
C. M.B.A.s versus non-M.B.A.s		
M.B.A.s		
Always	17	10.6
Sometimes	71	44.4
Never	72	45.0
Total	160	100.0
Non-M.B.A.s		
Always	28	20.4
Sometimes	44	32.1
Never	65	47.4
Total	137[a]	100.0

[a]Included 131 bachelor, 4 master, and 2 J.D. degrees for a total of 137.

reasonable level of significance on the basis of a chi-square independence of classification test (reported in Appendix B). The same conclusion applies in regard to the use of PV analysis by M.B.A.s versus non-M.B.A.s. If anything, non-M.B.A.s appear to be slightly higher users of PV analysis.

Table 5 shows the breakdown of the use of PV analysis by respondents' industry classifications. In this case, the chi-square test (see Appendix B) indicated a statistically significant difference between the categories. A null hypothesis of no relationship between industry classification and the use of PV analysis could be rejected at the 5 percent level of significance. In this sample, individuals employed by mutual funds and bank trust departments appear to be relatively high users of PV analysis whereas those working for brokerage firms, private money management groups, and investment banking firms do not.[4]

Other inputs. The respondents were also asked to determine the relative importance of other inputs in analyzing securities. Table 6 shows how the survey participants ranked the importance of earnings, cash flow, book value, and dividends. The average ranking for the input is shown in the far right column. Earnings and cash flow are considered far more important than book value and dividends.

The lack of importance these respondents assigned to dividends is interesting. As reported in Table 6, only 3 of the 297 respondents considered dividends to be the most important variable in valuing a security. One hypothesis is that such conclusions by analysts are linked to the irrelevance of dividends theory initially postulated by Modigliani and Miller (1961)—and debated ever since. But a far more likely cause of the low dividends ranking is that in the momentum-driven environment of 20–30 percent annual returns of the mid-to-late 1990s, dividends do not count for much in the minds of analysts. Furthermore, the sharply lower capital gains rates specified in the Taxpayer Relief Act of 1997 all but wiped out the equalization of taxing investment dividends and capital gains that was an essential element of the Reagan Tax Reform Act of 1986. Finally, the desire by corporations to buy back shares rather than increase cash dividends appears to be a distinctive feature of the 1990s.

Table 5. Industry Classification and Use of PV Techniques

Industry[a]	Always Number	Always Percent	Sometimes Number	Sometimes Percent	Never Number	Never Percent
Brokerage (77)	5	6.5	32	41.6	40	51.9
Private money management (75)	11	14.7	25	33.3	39	52.0
Investment management counseling (39)	3	7.7	19	48.7	17	43.6
Mutual fund (39)	12	30.8	16	41.0	11	28.2
Bank trust department (32)	10	31.2	8	25.0	14	43.8
Investment banking (18)	0	0.0	3	16.7	15	83.3
Other (12)	4	33.0	8	66.7	0	0.0
Pension fund (5)	0	0.0	5	100.0	0	0.0
Total	45		116		136	

[a]Total number in category in parentheses.

Table 6. Rank of Inputs in Importance

Variable	First	Second	Third	Fourth	Average Ranking
Earnings	156	118	23	0	1.55
Cash flow	133	140	19	5	1.65
Book value	5	32	133	127	3.29
Dividends	3	7	122	165	3.51

Not all would agree with the lack of importance of dividends. Bernstein (1998) made a strong case that management creates additional reinvestment and earnings risk for shareholders when the company retains a progressively larger percentage of earnings. The unimportance of dividends to this sample of analysts is further reflected, however, in **Table 7**, in which the respondents ranked the most significant inputs in determining a stock's P/E. Only 3 of the 297 respondents ranked dividend policy first among the five inputs listed; 276 ranked it last. Although analysts might change the rankings shown in Table 7 when valuing a real estate investment trust or a company in the later stages of its life cycle, the classification of dividends as unimportant is clear in Tables 6 and 7.

Also in Table 7, the growth potential for the company has a strong #1 ranking as a determinant of a stock's multiplier. The #2 ranking of quality of earnings (above quality of management, risks, and dividend policy) appears to reaffirm the strong concern that practicing analysts have for the legitimacy of reported earnings.

In another question related to valuation, I asked the respondents to rank the importance of the three inputs shown in **Table 8** as part of the determination of whether a stock should be bought, sold, or held. The long-term outlook for the company and the current value of the stock versus its historical trading range received top rankings; next quarter's EPS number was last by a large margin. This response is somewhat surprising; a click on the Internet will bring a deluge of under- and overperformance of quarterly earnings against expected earnings. Perhaps the 15.3 years average experience of the respondents allows them to overcome the hype of the moment.

Valuation Models. In addition to questions about the inputs to stock evaluation, the questionnaire asked respondents about their use of three valuation models. Panels A and B of **Table 9** provide the results for two traditional models—the dividend valuation (dividend discount) model and the capital asset pricing model (CAPM). Neither model fared well in the survey. The dividend model was viewed as very important or moderately important by 42 percent of the respondents, and the same two opinions totaled 31.1 percent for the CAPM.

The model that received the highest number of very or moderately important opinions, as indicated in Panel C of Table 9, is the economic value added (EVA) model developed by Stern Stewart and Company. Strictly speaking, EVA is not a valuation model, but it does have implications for describing stock price behavior. Based on these survey results, EVA may take on increasing importance for analysts. Whether the respondents understood that EVA is primarily a method for splitting earnings between required returns and excess returns is not evident from the questionnaire. Further inquiry about how analysts use EVA would thus be useful.

Portfolio Management

The issues discussed so far have dealt with valuing individual securities. The three items tabulated in **Table 10**—beliefs about market timing, the appeal

Table 7. Rank of Variables in Determining P/E

Variable	First	Second	Third	Fourth	Fifth	Average Ranking
Growth potential	205	62	18	12	0	1.45
Quality of earnings	43	104	115	35	0	2.48
Quality of management	31	74	112	71	9	2.84
Risks	15	56	44	170	12	3.36
Dividend policy	3	2	8	9	276	4.87

Table 8. Rank of Variables in Determining Buy, Hold, and Sell Decisions

Variable	First	Second	Third	Average Ranking
Current versus historical trading range	216	67	14	1.32
Long-term outlook for the company	76	171	50	1.91
Next quarter's EPS	5	59	233	2.77

Table 9. Importance of Models of Stock Price Behavior

Model	Number	Percent
A. Dividend valuation model		
Very important	34	11.8
Moderately important	87	30.2
Not very important	112	38.9
Unimportant	55	19.1
Total	288[a]	100.0
B. Capital asset pricing model		
Very important	5	1.8
Moderately important	83	29.3
Not very important	135	47.7
Unimportant	60	21.2
Total	283[b]	100.0
C. Economic value added		
Very important	41	14.4
Moderately important	151	53.2
Not very important	62	21.9
Unimportant	30	10.5
Total	284[c]	100.0

[a]Nine participants chose not to answer.
[b]Fourteen participants chose not to answer.
[c]Thirteen participants chose not to answer.

of global investing, and near-term reversion to the mean—relate more to portfolio management.

Panel A of Table 10 indicates that only 28.6 percent of the respondents believed that attempts at market timing are likely to enhance portfolio returns (the value is 32.7 percent if only those *with* opinions are included). The consistency of this response with the results shown in Panel C will be discussed shortly.

Table 10. Beliefs about Portfolio Management

Belief	Number	Percent	Among Those with Opinions
A. Does market timing enhance portfolio return?			
Yes	85	28.6	32.7%
No	175	58.9	67.3
No opinion	37	12.5	—
Total	297	100.0	100.0%
B. Has global investing lost appeal in more closely linked markets?			
No	37	12.5	
Some loss	202	68.2	
Substantial loss	57	19.3	
Total	296[a]	100.0	
C. Will there be a reversion to the mean in the next decade for yields and P/Es?			
Yes	171	57.6	71.6%
No	68	22.9	28.4
No opinion	58	19.5	—
Total	297	100.0	100.0%

[a]One participant chose not to answer.

Panel B of Table 10 deals with global investing. A major phenomenon portfolio managers have witnessed in the mid-to-late 1990s is the speed at which international financial markets react to each other. Market performance in the United States on a given day appears to start a chain reaction in London, Tokyo, and other major markets. The sequence may also move in the other direction. The internationalization of the world economy through reduced trading barriers and the increased merger activity between financial institutions in various countries appears to add to this chain reaction. The responses to Question 14 reported in Panel B give strong support to the notion that global investing may have lost some of its appeal in the closely linked markets as a means to achieve better risk–return outcomes through diversification. Slightly more that 87 percent of respondents believed there has been some loss or substantial loss of appeal.

Finally, Panel C of Table 10 addresses a question that all portfolio managers and analysts appear to be asking in the financial press—whether there will be a reversion to the mean for P/Es and dividend yields within the next decade. With the P/E for the S&P 500 Index in the 24–28 range and dividend yields in the 1.6–1.8 percent range in late 1998, this question is timely and of great interest to the profession and investors. Among the respondents, as indicated in Panel C, 57.6 percent expected a reversion to the mean. This statistic suggests that many believe equity values will be lower in the future, but responses to Question 7 (not reported here) indicate that respondents believe high values may be sustainable as long as interest rates and inflation remain low. The reversion is perhaps most likely to come when these mitigating variables are no longer in place.

The totality of information in Table 10 may reveal an inconsistency on the part of respondents. The majority did not believe in market timing but did believe in a coming reversion to the mean. Presumably, a reversion to the mean has implications for the timing of decisions.

Market Efficiency

The respondents were asked to indicate their acceptance or rejection of the efficient market hypothesis (EMH), which in its broadest (semistrong) form suggests that public information is impounded in the current price of the stock and that any additional analysis by an individual analyst is likely to produce little or nothing in the way of added value.[5] The EMH was initially postulated in the 1960s, and it has been under severe attack ever since as researchers claimed to identify anomalies in almost every area of investments. As shown in **Table 11**, close to 100 percent of practicing analysts in this survey were neutral or strongly disagreed with the EMH.

Table 11. Opinion of the Efficient Market Hypothesis

Opinion	Number	Percent
Strongly agree	8	2.7
Neutral	101	34.2
Strongly Disagree	186	63.1
Total	295[a]	100.0

[a]Two participants chose not to answer this question.

The responses to an allied topic are presented in **Table 12**. In answering a question about the most important variable in determining portfolio returns, more than 60 percent of the respondents chose the skill and training of the portfolio manager as most important. Despite the emphasis on the risk component often found in the academic literature, risk in the portfolio came in at about half the percentage of skill and training. And the amount of trading in the portfolio came in a poor third. These responses are generally in line with the rejection of the EMH reported in Table 11 but at variance with the responses to the usefulness of the CAPM shown in Table 9.

Table 12. Most Important Variable in Determining Portfolio Return

Variable	Number	Percent
The skill and training of the portfolio manager	179	60.3
The amount of risk in the portfolio	116	39.1
The amount of trading in the portfolio	2	0.6
Total	297	100.0

A number of respondents who indicated that skill and training was the most important variable in determining portfolio return suggested that ego might have played a role in their opinion. Such a suggestion would be consistent with the empirical research in this area in the past decades (Fama 1991; Kandel and Stambaugh 1996). Perhaps hope triumphed over reality for the majority of respondents.

To inquire into analysts' attitudes toward anomalies that tend to disprove the EMH, the respondents were given four market strategies from which to choose (Question 12). These four were by no means inclusive of all the possible strategies, and in spite of research in this area, no one answer can be assumed to be correct. The answers are presented in **Table 13**.

Table 13 shows that the low-P/E effect and the small-firm effect received the greatest allegiance. This response to the small-firm effect is of particular interest because the small-firm effect has been called too time-period specific and overly dependent on the month of January for high returns. As an example of the time-period specificity, research has found that between 1975 and 1983, small-capitalization stocks averaged a 35.3 percent annual return, more than twice the 15.7 percent return of large-cap stocks. During the same time period, compounded total returns on small-cap stocks exceeded 1,400 percent.[6] However, from 1984 to 1997, small-cap stocks (as defined by Ibbotson and Associates 1998) increased by 526.9 percent while large-cap stocks (S&P 500) were up 902.8 percent. When one strips the 1975–83 period out of the Ibbotson and Associates data, small-cap stocks *fell* one-third below large-cap stocks from 1926 through 1997.

Table 13. Statements about Market Anomalies with Which Respondents Agreed

Statement	Number Agreeing
Low-P/E stocks tend to outperform the market	184
Small-cap stocks tend to outperform the market	165
High-P/E growth stocks tend to outperform the market	39
Large-cap stocks tend to outperform the market	30
	418[a]

[a]Respondents could select more than one answer.

The intent here is not to castigate small-cap stocks; clearly, such stocks as Microsoft, Intel, and Home Depot had to start as small-cap stocks. Furthermore, for the particularly astute analyst, smaller companies may represent especially good areas for study, in that even the strongest advocates of the EMH would admit that small companies provide opportunities. The important point is that the strong support for the small-firm (and low-P/E) anomaly in this study may indicate that many practicing financial analysts maintain a belief in these concepts and a belief that a different market environment may bring the opportunity for strong small-cap performance to reappear. Also, the loyalty that some investors have shown to large-cap high-P/E stocks (such as Coca Cola and General Electric) is not necessarily felt by respondents in this study, who appear to be more value-stock than growth-stock oriented.

Conclusions

The most important conclusion from this survey is that PV techniques are not as widely used in practice as they are in theory. Only 54.3 percent of the respondents said they use PV analysis as part of their normal analytical process. The cause may be that the difficulties of projecting future cash flows and selecting an appropriate discount rate simply make use of PV analysis appear to be too difficult for real-life decisions. Although the length of forecasting periods was not specifically covered in the questionnaire, my observation is that few analysts project earnings or dividends more than two (or at most three) years into the future because of uncertainty. Also, they rarely project future P/Es. The industry practice is to divide the current price by future earnings to create a multiple of future earnings. This approach is, of course, very different from projecting a future P/E that can be used to discount a future stock price back to the present.

Answers to a number of questions indicate that the dividend-paying policy of a company is relatively unimportant in the analytical process. This attitude may be related to the current environment. In addition, although quarterly earnings announcements have received much attention in the financial press, 292 of the 297 analysts said quarterly earnings carry less weight than the long-term outlook for the company or its current versus historical trading range. The respondents gave high marks for importance to the EVA approach to valuation and low marks to the dividend valuation model and CAPM.

The respondents adhere to the notion that the most important variable in determining return on a portfolio is the skill and training of the portfolio manager and that this consideration overweights theories about stock market efficiency. Finally, respondents believe that global investing has lost some appeal as a risk–return optimizer in a world that appears to be increasingly integrated.

Notes

1. The original database from which names were drawn was the *1998 Membership Directory* of AIMR.
2. Although I am a CFA charterholder, I did not communicate that information to participants because of the concern that it could cause bias in answers.
3. The latest profile of AIMR membership can be found on AIMR's World Wide Web site: www.aimr.org.
4. Readers should not conclude anything beyond preliminary observations from these data because some of the industry classifications had relatively low numbers of respondents.
5. The semistrong form of the EMH asserts that only public information is impounded in the price. Some may suggest that the EMH is merely an unbiased estimator of current value, but the major thrust of the semistrong definition and the definition in Question 5 is the same.
6. For more discussion of the small-firm effect, see Chapter 6 in Siegel (1998).

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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

The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts

Robert S. Harris and Felicia C. Marston

Using expectational data from financial analysts, we estimate a market risk premium for US stocks. Using the S&P 500 as a proxy for the market portfolio, the average market risk premium is found to be 7.14% above yields on long-term US government bonds over the period 1982-1998. This risk premium varies over time; much of this variation can be explained by either the level of interest rates or readily available forward-looking proxies for risk. The market risk premium appears to move inversely with government interest rates suggesting that required returns on stocks are more stable than interest rates themselves. [JEL: G31, G12]

The notion of a market risk premium (the spread between investor required returns on safe and average risk assets) has long played a central role in finance. It is a key factor in asset allocation decisions to determine the portfolio mix of debt and equity instruments. Moreover, the market risk premium plays a critical role in the Capital Asset Pricing Model (CAPM), the most widely used means of estimating equity hurdle rates by practitioners. In recent years, the practical significance of estimating such a market premium has increased as firms, financial analysts, and investors employ financial frameworks to analyze corporate and investment performance. For instance, the increased use of Economic Value Added (EVA®) to assess corporate performance has provided a new impetus for estimating capital costs.

The most prevalent approach to estimating the market risk premium relies on some average of the historical spread between returns on stocks and bonds.[1] This choice has some appealing characteristics but is subject to many arbitrary assumptions such as the relevant period for taking an average. Compounding the difficulty of using historical returns is the well noted fact that standard models of consumer choice would predict much lower spreads between equity and debt returns than have occurred in US markets—the so called equity risk premium puzzle (see Welch, 2000 and Siegel and Thaler, 1997). In addition, theory calls for a forward-looking risk premium that could well change over time.

This paper takes an alternate approach by using expectational data to estimate the market risk premium. The approach has two major advantages for practitioners. First, it provides an independent estimate that can be compared to historical averages. At a minimum, this can help in understanding likely ranges for risk premia. Second, expectational data allow investigation of changes in risk premia over time. Such time variations in risk premia serve as important signals from investors that should affect a host of financial decisions. This paper provides new tests of whether changes in risk premia over time are linked to forward-looking measures of risk. Specifically, we look at the

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[1]Bruner, Eades, Harris, and Higgins (1998) provide survey evidence on both textbook advice and practitioner methods for estimating capital costs. As testament to the market for cost of capital estimates, Ibbotson Associates (1998) publishes a "Cost of Capital Quarterly."

relationship between the risk premium and four *ex-ante* measures of risk: the spread between yields on corporate and government bonds, consumer sentiment about future economic conditions, the average level of dispersion across analysts as they forecast corporate earnings, and the implied volatility on the S&P500 Index derived from options data.

Section I provides background on the estimation of equity required returns and a brief discussion of current practice in estimating the market risk premium. In Section II, models and data are discussed. Following a comparison of the results to historical returns in Section III, we examine the time-series characteristics of the estimated market premium in Section IV. Finally, conclusions are offered in Section V.

I. Background

The notion of a "market" required rate of return is a convenient and widely used construct. Such a rate (k) is the minimum level of expected return necessary to compensate investors for bearing the average risk of equity investments and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (e.g., bonds). To isolate the effects of risk, it is useful to work in terms of a market risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment.

Lacking a superior alternative, investigators often use averages of historical realizations to estimate a market risk premium. Bruner, Eades, Harris, and Higgins (1998) provide recent survey results on best practices by corporations and financial advisors. While almost all respondents used some average of past data in estimating a market risk premium, a wide range of approaches emerged. "While most of our 27 sample companies appear to use a 60+ year historical period to estimate returns, one cited a window of less than ten years, two cited windows of about ten years, one began averaging with 1960, and another with 1952 data" (p. 22). Some used arithmetic averages, and some used geometric. This historical approach requires the assumptions that past realizations are a good surrogate for future expectations and, as typically applied, that the risk premium is constant over time. Carleton and Lakonishok (1985) demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms. Siegel (1999) cites additional problems of using historical returns and argues that equity premium estimates from past data are likely too high. As Bruner et al. (1998) point out, few respondents cited use of expectational data to supplement or replace historical returns in estimating the market premium.

Survey evidence also shows substantial variation in empirical estimates. When respondents gave a precise estimate of the market premium, they cited figures from 4% to over 7% (Bruner et al., 1998). A quote from a survey respondent highlights the range in practice. "In 1993, we polled various investment banks and academic studies on the issue as to the appropriate rate and got anywhere between 2 and 8%, but most were between 6% and 7.4%." (Bruner et al., 1998). An informal sampling of current practice also reveals large differences in assumptions about an appropriate market premium. For instance, in a 1999 application of EVA analysis, Goldman Sachs Investment Research specifies a market risk premium of "3% from 1994-1997 and 3.5% from 1998-1999E for the S&P Industrials" (Goldman Sachs, 1999). At the same time, an April 1999 phone call to Stern Stewart revealed that their own application of EVA typically employed a market risk premium of 6%. In its application of the CAPM, Ibbotson Associates (1998) uses a market risk premium of 7.8%. Not surprisingly, academics do not agree on the risk premium either. Welch (2000) surveyed leading financial economists at major universities. For a 30-year horizon, he found a mean risk premium of 7.1% but a range from 1.5% to 15% with an interquartile range of 2.4% (based on 226 responses).

To provide additional insight on estimates of the market premium, we use publicly available expectational data. This expectational approach employs the dividend growth model (hereafter referred to as the discounted cash flow (DCF) model) in which a consensus measure of financial analysts' forecasts (FAF) of earnings is used as a proxy for investor expectations. Earlier work has used FAF in DCF models[2] but generally has covered a span of only a few years due to data availability.

II. Models and Data

The simplest and most commonly used version of the DCF model is employed to estimate shareholders' required rate of return, k, as shown in Equation (2):

[2]See Malkiel (1982), Brigham, Vinson, and Shome (1985), Harris (1986), and Harris and Marston (1992). The DCF approach with analysts' forecasts has been used frequently in regulatory settings. Ibbotson Associates (1998) use a variant of the DCF model with forward-looking growth rates; however, they do this as a separate technique and not as part of the CAPM. For their CAPM estimates, they use historical averages for the market risk premium.

$$k = \left(\frac{D_1}{P_0}\right) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share.[3] A primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expectations of future performance. This paper uses published FAF of long-run growth in earnings as a proxy for g. Equation (2) can be applied for an individual stock or any portfolio of companies. We focus primarily on its application to estimate a market premium as proxied by the S&P500.

FAF comes from IBES Inc. The mean value of individual analysts' forecasts of five-year growth rate in EPS is used as the estimate of g in the DCF model. The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. IBES requests "normalized" five-year growth rates from analysts in order to remove short-term distortions that might stem from using an unusually high or low earnings year as a base. Growth rates are available on a monthly basis.

Dividend and other firm-specific information come from COMPUSTAT. D_1 is estimated as the current indicated annual dividend times $(1+g)$. Interest rates (both government and corporate) are from Federal Reserve Bulletins and *Moody's Bond Record*. Exhibit 1 describes key variables used in the study. Data are used for all stocks in the *Standard and Poor's 500* stock (S&P500) index followed by IBES. Since five-year growth rates are first available from IBES beginning in 1982, the analysis covers the period from January 1982-December 1998.

The approach used is generally the same approach as used in Harris and Marston (1992). For each month, a market required rate of return is calculated using each dividend-paying stock in the S&P500 index for which data are available. As additional screens for reliability of data, in a given month we eliminate a firm if there are fewer than three analysts' forecasts or if the standard deviation around the mean forecast exceeds 20%. Combined, these two screens eliminate fewer than 20 stocks a month. Later we report on the sensitivity of the results to various screens. The DCF model in Equation (2) is applied to each stock and the results weighted by market value of equity to produce the market-required return. The risk premium is constructed by subtracting the interest rate on government bonds.

We weighted 1998 results by year-end 1997 market values since the monthly data on market value did not extend through this period. Since data on firm-specific dividend yields were not available for the last four months of 1998 at the time of this study, the market dividend yield for these months was estimated using the dividend yield reported in the *Wall Street Journal* scaled by the average ratio of this figure to the dividend yield for our sample as calculated in the first eight months of 1998. Adjustments were then made using growth rates from IBES to calculate the market required return. We also estimated results using an average dividend yield for the month that employed the average of the price at the end of the current and prior months. These average dividend yield measures led to similar regression coefficients as those reported later in the paper.

For short-term horizons (quarterly and annual), past research (Brown, 1993) finds that on average analysts' forecasts are overly optimistic compared to realizations. However, recent research on quarterly horizons (Brown, 1997) suggests that analysts' forecasts for S&P500 firms do not have an optimistic bias for the period 1993-1996. There is very little research on the properties of five-year growth forecasts, as opposed to shorter horizon predictions. Boebel (1991) and Boebel, Harris, and Gultekin (1993) examine possible bias in analysts' five-year growth rates. These studies find evidence of optimism in IBES growth forecasts. In the most thorough study to date, Boebel (1991) reports that this bias seems to be getting smaller over time. His forecast data do not extend into the 1990s.

Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our procedures will still yield unbiased estimates of required returns and risk premia. In light of the possible bias, however, we interpret the estimates as "upper bounds" for the market premium.

This study also uses four very different sources to create *ex ante* measures of equity risk at the market

[3]Our methods follow Harris (1986) and Harris and Marston (1992) who discuss earlier research and the approach employed here, including comparisons of single versus multistage growth models. Since analysts' forecast growth in earnings per share, their projections should incorporate the anticipated effects of share repurchase programs. Dividends per share would grow at the same rate as EPS as long as companies manage a constant ratio of dividends to earnings on a per share basis. Based on S&P500 figures (see the Standard and Poor's website for their procedures), the ratio of DPS to EPS was .51 during the period 1982-89 and .52 for the period 1990-98. Lamdin (2001) discusses some issues if share repurchases destroy the equivalence of EPS and DPS growth rates. Theoretically, i is a risk-free rate, though its empirical proxy is only a "least risk" alternative that is itself subject to risk. For instance, Asness (2000) shows that over the 1946-1998 period, bond volatility (in monthly realized returns) has increased relative to stock volatility, which would be consistent with a drop in the equity market premium.

Exhibit 1. Variable Definitions

k	=	Equity required rate return.
P_0	=	Price per share.
D_1	=	Expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1 + g)$.
g	=	Average financial analysts' forecast of five-year growth rate in earnings per share (from IBES).
i	=	Yield to maturity on long-term US government obligations (source: Federal Reserve, 30-year constant maturity series).
rp	=	Equity risk premium calculated as $rp = k - i$.
BSPREAD	=	spread between yields on corporate and government bonds, BSPREAD = yield to maturity on long-term corporate bonds (Moody's average across bond rating categories) minus i.
CON	=	Monthly consumer confidence index reported by the Conference Board (divided by 100).
DISP	=	Dispersion of analysts' forecasts at the market level.
VOL	=	Volatility for the S+P500 index as implied by options data.

level. The first proxy comes from the bond market and is calculated as the spread between corporate and government bond yields (BSPREAD). The rationale is that increases in this spread signal investors' perceptions of increased riskiness of corporate activity that would be translated to both debt and equity owners. The second measure, CON, is the consumer confidence index reported by the Conference Board at the end of the month. While the reported index tends to be around 100, we rescale CON as the actual index divided by 100. We also examined use of CON as of the end of the prior month; however, in regression analysis, this lagged measure generally was not statistically significant in explaining the level of the market risk premium.[4] The third measure, DISP, measures the dispersion of analysts' forecasts. Such analyst disagreement should be positively related to perceived risk since higher levels of uncertainty would likely generate a wider distribution of earnings forecasts for a given firm. DISP is calculated as the average of firm-specific standard deviations for each stock in the S&P500 covered by IBES. The firm-specific standard deviation is calculated based on the dispersion of individual analysts' growth forecasts around the mean of individual forecasts for that company in that month. DISP also was estimated using a value-weighted measure of analyst dispersion for the firms in our sample. The results reported use the equally weighted version but similar patterns were obtained with both constructions.[5] Our final measure, VOL, is the implied volatility on the S&P500 index. As of the beginning of the month, a dividend-adjusted Black Scholes Formula is used to estimate the implied volatility in the S&P500 index option contract, which expires on the third Friday of the month. The call premium, exercise price, and the level of the S&P500 index are taken from the *Wall Street Journal*, and treasury yields come from the Federal Reserve. Dividend yield comes from DRI. The option contract that is closest to being at the money is used.

III. Estimates of the Market Premium

Exhibit 2 reports both required returns and risk premia by year (averages of monthly data). The estimated risk premia are positive, consistent with equity owners demanding additional rewards over and above returns on debt securities. The average expectational risk premium (1982 to 1998) over

[4]We examined two other proxies for Consumer Confidence. The Conference Board's Consumer Expectations Index yielded essentially the same results as those reported. The University of Michigan's Consumer Sentiment Indices tended to be less significantly linked to the market risk premium, though coefficients were still negative.

[5]For the regressions reported in Exhibit 6, the value-weighted dispersion measure actually exhibited more explanatory power. For regressions using the Prais-Winsten method (see footnote 7), the coefficient on DISP was not significant in 2 of the 4 cases.

Exhibit 2. Bond Market Yields, Equity Required Return, and Equity Risk Premium, 1982-1998

Values are averages of monthly figures in percent. i is the yield to maturity on long-term government bonds, k is the required return on the S&P500 estimated as a value weighted average using a discounted cash flow model with analysts' growth forecasts. The risk premium $rp = k - i$. The average of analysts' growth forecasts is g. *Div yield* is expected dividend per share divided by price per share.

Year	Div. Yield	g	k	i	$rp = k - i$
1982	6.89	12.73	19.62	12.76	6.86
1983	5.24	12.60	17.86	11.18	6.67
1984	5.55	12.02	17.57	12.39	5.18
1985	4.97	11.45	16.42	10.79	5.63
1986	4.08	11.05	15.13	7.80	7.34
1987	3.64	11.01	14.65	8.58	6.07
1988	4.27	11.00	15.27	8.96	6.31
1989	3.95	11.08	15.03	8.45	6.58
1990	4.03	11.69	15.72	8.61	7.11
1991	3.64	11.99	15.63	8.14	7.50
1992	3.35	12.13	15.47	7.67	7.81
1993	3.15	11.63	14.78	6.60	8.18
1994	3.19	11.47	14.66	7.37	7.29
1995	3.04	11.51	14.55	6.88	7.67
1996	2.60	11.89	14.49	6.70	7.79
1997	2.18	12.60	14.78	6.60	8.17
1998	1.80	12.95	14.75	5.58	9.17
Average	3.86	11.81	15.67	8.53	7.14

government bonds is 7.14%, slightly higher than the 6.47% average for 1982 to 1991 reported by Harris and Marston (1992). For comparison purposes, Exhibit 3 contains historical returns and risk premia. The average expectational risk premium reported in Exhibit 2 is approximately equal to the arithmetic (7.5%) long-term differential between returns on stocks and long-term government bonds.[6]

Exhibit 2 shows the estimated risk premium changes over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities. Scanning the last column of Exhibit 2, the risk premium is higher in the 1990s than earlier and especially so in late 1997 and 1998. Our DCF results provide no evidence to support the notion of a declining risk premium in the 1990s as a driver of the strong run up in equity prices.

A striking feature in Exhibit 2 is the relative stability of the estimates of k. After dropping (along with interest rates) in the early and mid-1980s, the average annual value of k has remained within a 75 basis point range around 15% for over a decade. Moreover, this stability arises despite some variability in the

[6]Interestingly, for the 1982-1996 period the arithmetic spread between large company stocks and long-term government bonds was only 3.3% per year. The downward trend in interest rates resulted in average annual returns of 14.1% on long-term government bonds over this horizon. Some (e.g., Ibbotson, 1997) argue that only the income (not total) return on bonds should be subtracted in calculating risk premia.

Exhibit 3. Average Historical Returns on Bonds, Stocks, Bills, and Inflation in the US, 1926-1998

Historical Return Realizations	Geometric Mean	Arithmetic Mean
Common Stock (Large Company)	11.2%	13.2%
Long-term Government Bonds	5.3	5.7
Treasury Bills	3.8	3.8
Inflation Rate	3.1	3.2

Source: Ibbotson Associates, Inc., *1999 Stocks, Bonds, Bills and Inflation*, 1999 Yearbook.

underlying dividend yield and growth components of k as Exhibit 2 illustrates. The results suggest that k is more stable than government interest rates. Such relative stability of k translates into parallel changes in the market risk premium. In a subsequent section, we examine whether changes in our market risk premium estimates appear linked to interest rate conditions and a number of proxies for risk.

We explored the sensitivity of the results to our screening procedures in selecting companies. The reported results screen out all non-dividend paying stocks on the premise that use of the DCF model is inappropriate in such cases. The dividend screen eliminates an average of 55 companies per month. In a given month, we also screen out firms with fewer than three analysts' forecasts, or if the standard deviation around the mean forecast exceeds 20%. When the analysis is repeated without any of the three screens, the average risk premium over the sample period increased by only 40 basis points, from 7.14% to 7.54%. The beta of the sample firms also was estimated and the sample average was one, suggesting that the screens do not systematically remove low or high-risk firms. (Specifically, using firms in the screened sample as of December 1997 (the last date for which we had CRSP return data), we used ordinary least squares regressions to estimate beta for each stock using the prior 60 months of data and the CRSP return (SPRTRN) as the market index. The value-weighted average of the individual betas was 1.00.)

The results reported here use firms in the S&P500 as reported by COMPUSTAT in September 1998. This could create a survivorship bias, especially in the earlier months of the sample. We compared our current results to those obtained in Harris and Marston (1992) for which there was data to update the S&P500 composition each month. For the overlapping period, January 1982-May 1991, the two procedures yield the same average market risk premium, 6.47%. This suggests that the firms departing from or entering the S&P500 index do so for a number of reasons with no discernable effect on the overall estimated S&P500 market risk premium.

IV. Changes in the Market Risk Premium Over Time

With changes in the economy and financial markets, equity investments may be perceived to change in risk. For instance, investor sentiment about future business conditions likely affects attitudes about the riskiness of equity investments compared to investments in the bond markets. Moreover, since bonds are risky investments themselves, equity risk premia (relative to bonds) could change due to changes in perceived riskiness of bonds, even if equities displayed no shifts in risk.

In earlier work covering the 1982-1991 period, Harris and Marston (1992) reported regression results indicating that the market premium decreased with the level of government interest rates and increased with the spread between corporate and government bond yields (BSPREAD). This bond yield spread was interpreted as a time series proxy for equity risk. In this paper, we introduce three additional *ex ante* measures of risk shown in Exhibit 1: CON, DISP, and VOL. The three measures come from three independent sets of data and are supplied by different agents in the economy (consumers, equity analysts, and investors (via option and share price data)). Exhibit 4 provides summary data on all four of these risk measures.

Exhibit 5 replicates and updates earlier analysis by Harris and Marston (1992).[7] The results confirm the earlier patterns. For the entire sample period, Panel A shows that risk premia are negatively related to interest rates. This negative relationship is also true for both

[7]OLS regressions with levels of variables generally showed severe autocorrelation. As a result, we used the Prais-Winsten method (on levels of variables) and also OLS regressions on first differences of variables. Since both methods yielded similar results and the latter had more stable coefficients across specifications, we report only the results using first differences. Tests using Durbin-Watson statistics from regressions in Exhibits 5 and 6 do not accept the hypothesis of autocorrelated errors (tests at .01 significance level, see Johnston, 1984). We also estimated the first difference model without an intercept and obtained estimates almost identical to those reported.

Exhibit 4. Descriptive Statistics on *Ex Ante* Risk Measures

Entries are based on monthly data. BSPREAD is the spread between yields on long-term corporate and government bonds. CON is the consumer confidence index. DISP measures the dispersion of analysts' forecasts of earnings growth. VOL is the volatility on the S&P500 index implied by options data. Variables are expressed in decimal form, (e.g., 12% = .12).

Panel A. Variables are Monthly Levels				
	Mean	**Standard Deviation**	**Minimum**	**Maximum**
BSPREAD	.0123	.0040	.0070	.0254
CON	.9504	.2242	.473	1.382
DISP	.0349	.0070	.0285	.0687
VOL	.1599	.0697	.0765	.6085
Panel B. Variables are Monthly Changes				
	Mean	**Standard Deviation**	**Minimum**	**Maximum**
BSPREAD	-.00001	.0011	-.0034	.0036
CON	.0030	.0549	-.2300	.2170
DISP	-.00002	.0024	-.0160	.0154
VOL	-.0008	.0592	-.2156	.4081
Panel C. Correlation Coefficients for Monthly Changes				
	BSPREAD	**CON**	**DISP**	**VOL**
BSPREAD	1.00	-.16**	.054	.22*
CON	-.16**	1.00	.065	-.09
DISP	.054	.065	1.00	.027
VOL	.22*	-.09	.027	1.00

**Significantly different from zero at the .05 level.
*Significantly different from zero at the .01 level.

the 1980s and 1990s as displayed in Panels B and C. For the entire 1982 to 1998 period, the addition of the yield spread risk proxy to the regressions lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations (1) and (2) of Panel A. Furthermore, the coefficient of the yield spread (0.488) is itself significantly positive. This pattern suggests that a reduction in the risk differential between investment in government bonds and in corporate bonds is translated into a lower equity market risk premium.

In major respects, the results in Exhibit 5 parallel earlier findings. The market risk premium changes over time and appears inversely related to government interest rates but is positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds. One striking feature is the large negative coefficients on government bond yields. The coefficients indicate the equity risk premium declines by over 70 basis points for a 100 basis point increase in government interest rates.[8] This inverse relationship suggests

[8]The Exhibit 5 coefficients on i are significantly different from −1. 0 suggesting that equity required returns do respond to interest rate changes. However, the large negative coefficients imply only minor adjustments of required returns to interest rate changes since the risk premium declines. In earlier work (Harris and Marston, 1992) the coefficient was significantly negative but not as large in absolute value. In that earlier work, we reported results using the Prais-Winsten estimators. When we use that estimation technique and recreate the second regression in Exhibit 5, the coefficient for i is -.584 (t = - 12.23) for the entire sample period 1982-1998.

Exhibit 5. Changes in the Market Equity Risk Premium Over Time

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as monthly changes to correct for autocorrelation. The dependent variable is the market equity risk premium for the S&P500 index. BSPREAD is the spread between yields on long-term corporate and government bonds. The yield to maturity on long-term government bonds is denoted as i. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Time Period	Intercept	i	BSPREAD	R^2
A. 1982-1998	-.0002	-.869		.57
	(-1.49)	(-16.54)		
	-.0002	-.749	.488	.59
	(-1.11)	(-11.37)	(2.94)	
B. 1980s	-.0005	-.887		.56
	(-1.62)	(-10.97)		
	-.0004	-.759	.508	.57
	(-1.24)	(-7.42)	(1.99)	
C. 1990s	-.0000	-.840		.64
	(-0.09)	(-13.78)		
	-.0000	-.757	.347	.65
	(0.01)	(-9.85)	(1.76)	

Exhibit 6. Changes in the Market Equity Risk Premium Over Time and Selected Measures of Risk

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as monthly changes to correct for autocorrelation. The dependent variable is the market equity risk premium for the S&P500 index. BSPREAD is the spread between yields on long-term corporate and government bonds. The yield to maturity on long-term government bonds is denoted as i. CON is the consumer confidence index. DISP measures the dispersion of analysts' forecasts of earnings growth. VOL is the volatility on the S&P500 index implied by options data. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Time Period		Intercept	i	BSPREAD	CON	DISP	VOL	Adj. R^2
A. 1982-1998								
	(1)	0.0002			-0.014			0.05
		(.97)			(-3.50)			
	(2)	-0.0001	-0.737	0.453	-0.007			0.60
		(-.96)	(-11.31)	(2.76)	(-2.48)			
	(3)	0.0002				0.224		0.02
		(.79)				(2.38)		
	(4)	-0.0001	-0.733	0.433	-0.007	0.185		0.62
		(-.93)	(-11.49)	(2.69)	(-2.77)	(3.13)		
B. May 1986-1998	(5)	0.0000	-0.818	0.420	-0.005	0.378		0.68
		(.06)	(-11.21)	(2.52)	(-2.23)	(3.77)		
	(6)	0.0001					0.011	0.05
		(.53)					(2.89)	
	(7)	0.0000	-0.831	0.326	-0.005	0.372	0.006	0.69
		(.02)	(-11.52)	(1.95)	(-2.12)	(3.77)	(2.66)	

much greater stability in equity required returns than is often assumed. For instance, standard application of the CAPM suggests a one-to-one change in equity returns and government bond yields.

Exhibit 6 introduces three additional proxies for risk and explores whether these variables, either individually or collectively, are correlated with the market premium. Since the estimates of implied volatility start in May 1986, the exhibit shows results for both the entire sample period and for the period during which we can introduce all variables. Entered individually each of the three variables is significantly linked to the risk premium with the coefficient having the expected sign. For instance, in regression (1) the coefficient on CON is -.014, which is significantly different from zero (t = -3.50). The negative coefficient signals that higher consumer confidence is linked to a lower market premium. The positive coefficients on VOL and DISP indicate the equity risk premium increases with both market volatility and disagreement among analysts. The effects of the three variables appear largely unaffected by adding other variables. For instance, in regression (4) the coefficients on CON and DISP both remain significant and are similar in magnitude to the coefficients in single variable regressions.[9]

Even in the presence of the new risk variables, Exhibit 6 shows that the market risk premium is affected by interest rate conditions. The large negative coefficient on government bond rates implies large reductions in the equity premium as interest rates rise. One feature of our data may contribute to the observed negative relationship between the market risk premium and the level of interest rates. Specifically, if analysts are slow to report updates in their growth forecasts, changes in the estimated k would not adjust fully with changes in the interest rate even if the true risk premium were constant. To address the impact of "stickiness" in the measurement of k, we formed "quarterly" measures of the risk premium that treat k as an average over the quarter. Specifically, we take the value of k at the end of a quarter and subtract from it the average value of i for the months ending when k is measured. For instance, to form the risk premium for March 1998, the average value of i for January, February, and March is subtracted from the March value of k. This approach assumes that, in March, k still reflects values of g that have not been updated from the prior two months. The quarterly measure of risk premium then is paired with the average values of the other variables for the quarter. For instance, the March 1998 "quarterly" risk premium would be paired with averaged values of BSPREAD over the January through March period. To avoid overlapping observations for the independent variables, we use only every third month (March, June, September, December) in the sample.

As reported in Exhibit 7, sensitivity analysis using "quarterly" observations suggests that delays in updating may be responsible for a portion, but not all, of the observed negative relationship between the market premium and interest rates. For example, when quarterly observations are used, the coefficient on i in regression (2) of Exhibit 7 is -.527, well below the earlier estimates but still significantly negative.[10]

As an additional test, movements in the bond risk premium (BSPREAD) are examined. Since BSPREAD is constructed directly from bond yield data, it does not have the potential for reporting lags that may affect analysts' growth forecasts. Regression 3 in Exhibit 7 shows BSPREAD is negatively linked to government rates and significantly so.[11] While the equity premium need not move in the same pattern as the corporate bond premium, the negative coefficient on BSPREAD suggests that our earlier results are not due solely to "stickiness" in measurements of market required returns.

The results in Exhibit 7 suggest that the inverse relationship between interest rates and the market risk premium may not be as pronounced as suggested in earlier exhibits. Still, there appears to be a significant negative link between the equity risk premium and government interest rates. The quarterly results in Exhibit 7 would suggest about a 50 basis point change in risk premium for each 100 basis point movement in interest rates.

Overall, the *ex ante* estimates of the market risk premium are significantly linked to *ex ante* proxies for risk. Such a link suggests that investors modify their required returns in response to perceived changes in the environment. The findings provide some comfort that our risk premium estimates are capturing, at least

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[9]Realized equity returns are difficult to predict out of sample (see Goyal and Welch, 1999). Our approach is different in that we look at expectational risk premia which are much more stable. For instance, when we estimate regression coefficients (using the specification shown in regression 7 of Exhibit 6) and apply them out of sample we obtain "predictions" of expectational risk premia that are significantly more accurate (better than the .01 level) than a no change forecast. We use a "rolling regression" approach using data through December 1991 to get coefficients to predict the risk premium in January 1992. We repeat the procedure moving forward a month and dropping the oldest month of data from the regression. Details are available from the authors.

[10]Sensitivity analysis for the 1982-1989 and 1990-1998 subperiods yields results similar to those reported.

[11]We thank Bob Conroy for suggesting use of BSPREAD. Regression 3 in Exhibit 7 appears to have autocorrelated errors: the Durbin-Watson (DW) statistic rejects the hypothesis of no autocorrelation. However, in subperiod analysis, the DW statistic for the 1990-98 period is consistent with no autocorrelation and the coefficient on i is essentially the same (-.24, t = -8.05) as reported in Exhibit 7.

Exhibit 7. Regressions Using Alternate Measures of Risk Premia to Analyze Potential Effects of Reporting Lags in Analysts' Forecasts

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as changes (monthly or quarterly) to correct for autocorrelation. BSPREAD is the spread between yields on long-term corporate and government bonds. rp is the risk premium on the S&P500 index. The yield to maturity on long-term government bonds is denoted as i. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Dependent Variable	Intercept	i	BSPREAD	Adj. R^2
(1) Equity Risk Premium (rp) Monthly Observations (same as Table V)	-.0002 (-1.11)	-.749 (-11.37)	.488 (2.94)	.59
(2) Equity Risk Premium (rp) "Quarterly" nonoverlapping observations to account for lags in analyst reporting	-.0002 (-.49)	-.527 (-6.18)	.550 (2.20)	.60
(3) Corporate Bond Spread (BSPREAD) Monthly Observations	-.0001 (-1.90)	-.247 (-11.29)		.38

in part, underlying changes in the economic environment. Moreover, each of the risk measures appears to contain relevant information for investors. The market risk premium is negatively related to the level of consumer confidence and positively linked to interest rate spreads between corporate and government debt, disagreement among analysts in their forecasts of earnings growth, and the implied volatility of equity returns as revealed in options data.

V. Conclusions

Shareholder required rates of return and risk premia should be based on theories about investors' expectations for the future. In practice, however, risk premia are typically estimated using averages of historical returns. This paper applies an alternate approach to estimating risk premia that employs publicly available expectational data. The resultant average market equity risk premium over government bonds is comparable in magnitude to long-term differences (1926 to 1998) in historical returns between stocks and bonds. As a result, our evidence does not resolve the equity premium puzzle; rather, the results suggest investors still expect to receive large spreads to invest in equity versus debt instruments.

There is strong evidence, however, that the market risk premium changes over time. Moreover, these changes appear linked to the level of interest rates as well as *ex ante* proxies for risk drawn from interest rate spreads in the bond market, consumer confidence in future economic conditions, disagreement among financial analysts in their forecasts and the volatility of equity returns implied by options data. The significant economic links between the market premium and a wide array of risk variables suggests that the notion of a constant risk premium over time is not an adequate explanation of pricing in equity versus debt markets.

These results have implications for practice. First, at least on average, the estimates suggest a market premium roughly comparable to long-term historical spreads in returns between stocks and bonds. Our conjecture is that, if anything, the estimates are on the high side and thus establish an upper bound on the market premium. Second, the results suggest that use of a constant risk premium will not fully capture changes in investor return requirements. As a specific example, our findings indicate that common application of models such as the CAPM will overstate changes in shareholder return requirements when government interest rates change. Rather than a one-for-one change with interest rates implied by use of constant risk premium, the results indicate that equity required returns for average risk stocks likely change by half (or less) of the change in interest rates. However, the picture is considerably more complicated as shown by the linkages between the risk premium and other attributes of risk.

Ultimately, our research does not resolve the answer to the question "What is the right market risk premium?" Perhaps more importantly, our work suggests that the answer is conditional on a number of features in the economy—not an absolute. We hope that future research will harness *ex ante* data to provide additional guidance to best practice in using a market premium to improve financial decisions.■

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Analyst Forecasting Errors: Additional Evidence

Lawrence D. Brown

Analyst forecasting errors are approximately as large as Dreman and Berry (1995) documented, and an optimistic bias is evident for all years from 1985 through 1996. In contrast to their findings, I show that analyst forecasting errors and bias have decreased over time. Moreover, the optimistic bias in quarterly forecasts was absent for S&P 500 firms from 1993 through 1996. Analyst forecasting errors are smaller for (1) S&P 500 firms than for other firms; (2) firms with comparatively large amounts of market capitalization, absolute value of earnings forecast, and analyst following; and (3) firms in certain industries.

In recent issues of this journal, David Dreman, Michael Berry, and I have presented alternative views of analysts' earnings forecast errors and their implications for security analysis (Dreman and Berry 1995, Brown 1996, Dreman 1996). The first two papers provided alternative views concerning several issues, including whether (1) analysts' earnings forecast errors are "too large," (2) analysts' earnings forecast errors have increased over time, and (3) analysts' earnings forecasts are optimistically biased.

In the opinion of Dreman and Berry, analysts' earnings forecast errors are too large, and using the deflators the authors suggested (e.g., actual or predicted earnings), analyst forecasting errors do appear large. If analysts' earnings forecast errors are deflated by stock price, however, or compared with forecasts based on extrapolative techniques, they do not appear too large. Dreman–Berry also maintained that analysts' earnings forecasting errors have increased over time. My analysis of their findings, however, suggested that the accuracy of analysts' earnings forecasts has actually improved over time. In addition, Dreman–Berry provided evidence that analysts' earnings forecasts are biased toward optimism. Relying on information provided by I/B/E/S International, I showed that an optimistic bias was absent for S&P 500 firms for the 11 quarters from first-quarter 1993 through third-quarter 1995.

In his letter to the editor, Dreman (1996) responded to the views I expressed in my article, disagreeing with most of them. He correctly observed that much of my analysis was based on the Abel–Noser database, which Dreman–Berry had used but which was inaccessible to me; my analysis relied on summary information provided in the Dreman–Berry article. Moreover, although not stated by Dreman, neither did I examine the I/B/E/S data that I had relied on in my 1996 article. Instead, I relied on summary information provided to me by I/B/E/S.

This article is based on I/B/E/S data for fourth-quarter 1983 through second-quarter 1996. It presents evidence regarding the following issues:

- Is the Dreman–Berry result that analyst forecasting errors are "too large" robust to using a different data source than the Abel–Noser database?
- Is the Dreman–Berry conclusion that analysts' forecasting errors have increased over time robust to using I/B/E/S data? Does it pertain equally to S&P 500 firms and other firms?
- Is the optimistic bias documented by Dreman–Berry robust to using I/B/E/S data? Does this optimism pertain equally to S&P 500 and other firms? Has it been mitigated over time? Is the extent of mitigation similar for both S&P 500 firms and other firms?
- Do analyst forecasting errors and bias differ depending on such firm-specific factors as market capitalization, absolute value of predicted EPS, analyst following, and industry classification?

PRELIMINARY RESULTS

Dreman and Berry relied on the Abel–Noser database, which uses information from Value Line, Zacks Investment Research, I/B/E/S, and First Call. Because different vendors of analyst forecasts define both forecasted and actual earnings numbers differently, mixing data from different vendors introduces error (Philbrick and Ricks 1991), potentially making analysts' earnings forecast errors appear larger than they actually are. For this study, I used the data of a single vendor, I/B/E/S, for the

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time period from fourth-quarter 1983 through second-quarter 1996. The sample consists of all U.S. firms for which analyst earnings forecast errors could be calculated.

Figure 1 provides frequency distributions using the SURPE and SURPF definitions of analyst forecasting errors (earnings surprise), defined as

SURPE = (Actual quarterly earnings – Predicted quarterly earnings)/|Actual quarterly earnings|

SURPF = (Actual quarterly earnings – Predicted quarterly earnings)/ | Predicted quarterly earnings |.

Predicted quarterly earnings were obtained from the I/B/E/S summary tape using the last consensus (mean) estimate prior to the firm's quarterly earnings announcement.[1]

SURPE and SURPF are two of the four definitions of earnings surprise Dreman–Berry and I used in our research.[2] My Figure 1 corresponds to their Figure 1 pertaining to SURPE and SURPF, and my results are very similar to theirs. More specifically, the modal and median values of earnings surprise are zero; *small* positive errors are more frequent than negative errors; and *large* negative errors outnumber positive errors. These findings suggest that whereas analysts are more likely to be on target than anywhere else, managers manipulate earnings in a way to generate a considerable number of small positive (relative to small negative) surprises and large negative (relative to large positive) surprises ("big baths").[3]

I/B/E/S VERSUS ABEL–NOSER DATA

Table 1 provides summary statistics on the I/B/E/S and Abel–Noser data. The I/B/E/S results are based on my analysis of these data; the Abel–Noser results are reproduced from Dreman–Berry's Table 1. The average error (mean absolute surprise) using the I/B/E/S data is substantially larger than that using the Abel–Noser data. The I/B/E/S SURPE of 0.590 is approximately one-third greater than the Abel–Noser SURPE of 0.438, and the I/B/E/S SURPF of 0.916 is more than twice as large as the Abel–Noser SURPF of 0.415. Moreover, the mean surprise (bias) using the I/B/E/S data is also substantially larger in absolute value than that documented by Dreman–Berry using the Abel–Noser data. More particularly, the I/B/E/S SURPE and SURPF are –0.316 and –0.414, respectively, compared with the Abel–Noser SURPE and SURPF of –0.250 and –0.111.

My results could differ from Dreman–Berry's because of different sample-selection procedures. Dreman–Berry's sample is confined to firms with fiscal years ending in March, June, September, or December that are followed (after 1981) by at least four analysts. When the I/B/E/S sample is similarly restricted, the results are nearly identical to Dreman–Berry's.[4] More particularly, for the 46,859 I/B/E/S observations that satisfy these criteria, the average absolute surprise of 0.416 (SURPE definition) is similar to Dreman–Berry's 0.438, and the mean SURPE of –0.218 using the I/B/E/S sample closely approximates Dreman–Berry's –0.250.

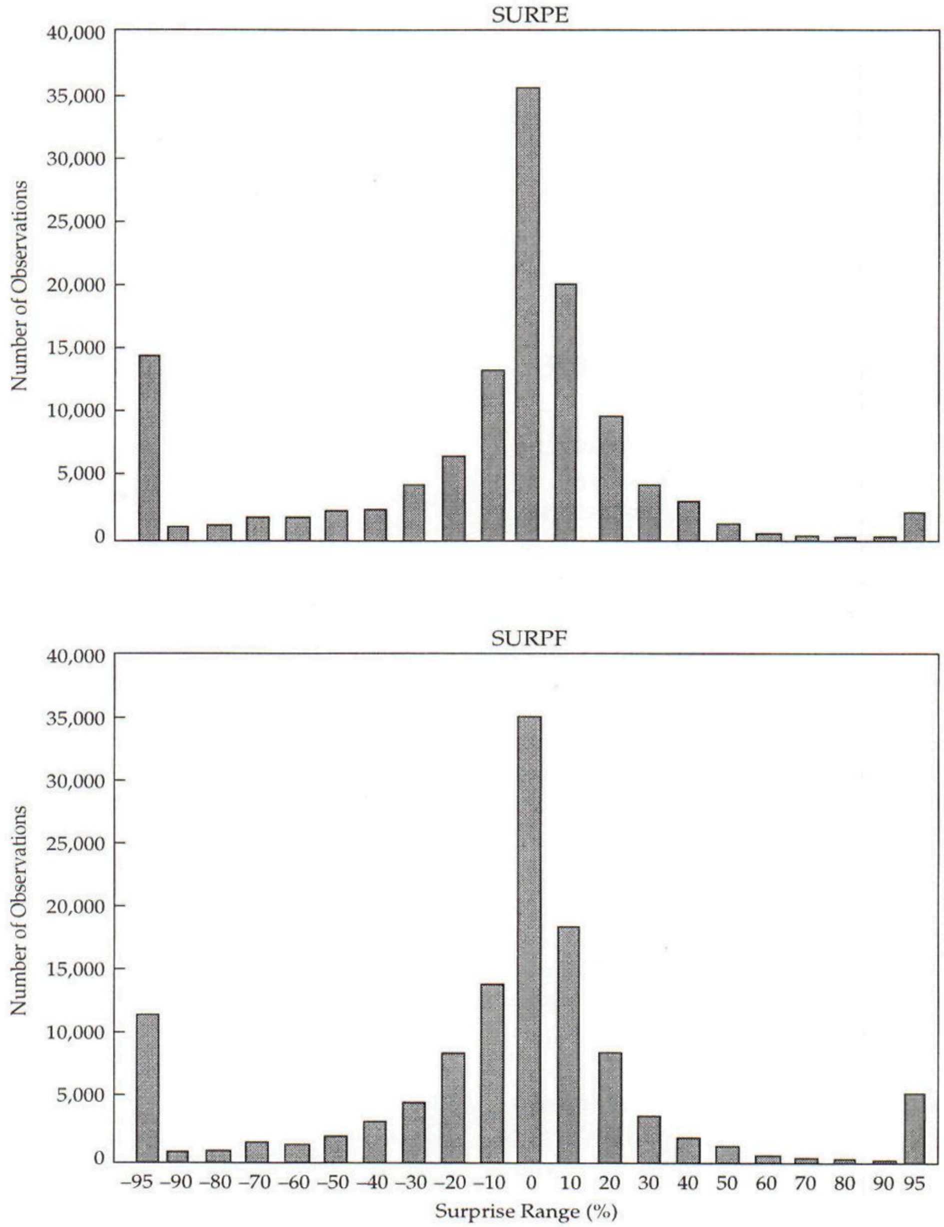
From these results, I conclude that the Dreman–Berry finding of large analyst forecasting errors is robust to using a different data source. Dreman–Berry used Abel–Noser data and examined the first-quarter 1974 through fourth-quarter 1991 time period; I obtained similar results using the I/B/E/S data for fourth-quarter 1983 through second-quarter 1996.

HAVE FORECASTING ERRORS CHANGED?

Evidence regarding five definitions of error—mean absolute surprise, mean surprise (bias), and the proportion of errors outside the +/–10 percent, +10 percent, and –10 percent bandwidths—is presented in Table 2 for all firms, S&P 500 firms, and non-S&P 500 firms.[5] All five error metrics use the SURPF definition of earnings surprise, which has predicted quarterly earnings as its deflator. Dreman–Berry provided evidence pertaining to three +/– bandwidths: 5 percent, 10 percent, and 15 percent. I focused on the second of these bandwidths, +/–10 percent, and considered its plus and minus sides separately.[6]

Dreman–Berry concluded that analyst forecasting errors increase over time. In contrast, Table 2 reveals that both mean absolute surprise and mean surprise (bias) have *decreased* significantly over time. This result is borne out by the rank correlations of analyst forecasting error with year, which are –0.973 and 0.489 for mean absolute surprise and mean surprise, respectively.[7] Nevertheless, the mean surprise is negative and significant in every year from 1985 through 1996, suggesting that, although the optimistic bias has been mitigated, it remains significant. The rank correlations of time with the proportion of errors outside the +/–10 percent, +10 percent, and –10 percent bandwidths are –0.995, –0.038, and –0.945, respectively. The –10 percent bandwidth result is significant, but the +10 percent bandwidth result is not. Thus, the temporal reduction of error results from mitigation of the optimistic bias. Indeed, no temporal reduction in the percentage of large positive errors (i.e., earnings *underestimates*) has occurred.

Figure 1. Histograms of SURPE and SURPF



Comparison of S&P 500 firms with other firms is important because many investors invest exclusively in S&P 500 firms and/or use the S&P 500 Index as a benchmark. Analyst forecasting errors are much smaller for S&P 500 firms than for other firms. More specifically, in *every* year, the mean absolute surprise and the proportion of forecasts outside the +/–10 percent, +10 percent, and –10 percent bandwidths is smaller for the S&P 500 firms than it is for the other firms. Clearly, the earnings of S&P 500 firms are easier to forecast than are those of non-S&P 500 firms.

Although forecasts for S&P 500 firms exhibit a significant optimistic bias for the 1984–96 period as a whole, the optimistic bias in forecasting quarterly earnings of S&P 500 firms disappeared as of 1993. More specifically, for S&P 500 firms, a significant optimistic bias is evident in every year in the 1985–92 period but not in the four most recent years, 1993 through 1996. In contrast, the bottom panel of Table 2 reveals that the optimistic bias in forecasting quarterly earnings of other (non-S&P 500) firms exists in all 12 years, 1985 through 1996. Perhaps the disappearance of the optimistic bias for S&P 500 firms is attributable to mitigation of the big-bath phenomenon or a lessening of the tendency of these firms' managers to manipulate earnings in a way to generate a large number of small positive (relative to small negative) surprises.[8]

Table 1. Descriptive Statistics for Earnings Forecast Errors

	I/B/E/S (4Q 1983–2Q 1996)		Abel–Noser (1Q 1974–4Q 1991)	
Statistic	SURPE	SURPF	SURPE	SURPF
Number of forecasts	129,436		66,100	
Mean absolute surprise	0.590	0.916	0.438	0.415
Mean surprise (bias)	–0.316*	–0.414*	–0.250*	–0.111*
Median	0.000	0.000	0.000	0.000
Maximum	314.000	863.000	49.000	48.000
Minimum	–186.259	–819.000	–216.000	–282.600

Note: SURPE (SURPF) is consensus EPS surprise as a percent of absolute value of actual (forecast) EPS.
*Significant at the 5 percent level, two-tailed test.

DO FORECASTING ERRORS DIFFER BY FIRM-SPECIFIC FACTORS?

Table 3 shows whether errors differ by market capitalization, absolute value of earnings forecast, or analyst following. Such comparisons are relevant because many investors invest primarily in large firms, firms with comparatively large earnings forecasts, or firms with relatively heavy analyst following. For these investors, the average analyst earnings forecast error per se is less relevant than the average forecasting error for these firm-specific subsamples.

The market capitalization results are monotonic for four of the five error measures: mean absolute surprise, mean surprise, and proportion of errors outside the +/–10 percent and –10 percent bandwidths. The highest capitalization group (i.e., firms with market caps in excess of $3 billion) has a smaller proportion of errors outside the +10 percent bandwidth than do any of the other market cap groups. Regarding bias, a significant optimistic bias (negative mean surprise) is evident for all market caps except the largest one.

The absolute value of earnings forecast results is not monotonic for any of the five definitions of error. Nevertheless, the mean absolute surprise and the mean surprise (bias) results are nearly monotonic; the exception occurs when forecasted earnings are at least $1. For this group, the mean absolute surprise and the mean surprise (bias) are approximately halfway between what they are for the [$0.10, $0.25) and [$0.25, $0.50) groups. The bandwidth results are similar to the mean absolute surprise and bias results in that the largest absolute value of earnings forecast group (i.e., ≥ $1) does not have the smallest proportion of errors outside the +/–10 percent, +10 percent, or –10 percent bandwidths.[9]

Similar to the absolute value of earnings forecast results, the analyst-following results are not monotonic for any of the five definitions of error. Nevertheless, the results are monotonic for all five error measures as the number of analysts increases from 1 to 5, and the smallest errors are obtained for the largest analyst following (10 or more) for four of the error measures.[10] Moreover, the rank correlations for the five error measures range from an absolute value of 0.782 to 0.988, and they all are statistically significant. Thus, error generally decreases when analyst following increases.

DO FORECASTING ERRORS DIFFER BY SECTOR?

The five error metrics are provided in Table 4 for each of the 14 industries in the I/B/E/S sample with data pertaining to at least 50 firms. The mean absolute surprise ranges from a low of 0.255 to a high of 1.663. Two industries have a mean absolute surprise below 0.400: food and kindred products (0.255) and holding companies and other investment offices (0.392). At the other extreme, two industries have mean absolute surprises in excess of 1.0: oil and gas extraction (1.663) and primary metal industries (1.267).

Eleven of the 14 industries evidence a significant optimistic bias. Optimistic bias for the other three—transportation equipment, communications, and insurance carriers—is not significant. The mean surprises range from a low of –0.068 to a high of –0.721. Three industries have an optimistic bias below 0.080 in absolute value: food and kindred products (–0.068), transportation equipment (–0.070), and communications (–0.076). At the other extreme, two industries have an optimistic bias above 0.500 in absolute value: oil and gas extraction (–0.721) and primary metal industries (–0.532).

The proportion of analyst forecasting errors outside the +/–10 percent bandwidth ranges from a low of 0.361 to a high of 0.780. Two industries have less than 40 percent of their observations outside the +/–10 percent bandwidth: food and kindred products (0.361) and depository institutions (0.369). At the other extreme, two industries have more than two-thirds of their observations outside the +/–10 percent bandwidth: oil and gas extraction (0.780) and primary metal industries (0.683). Twelve of the 14 industries have more errors outside the –10 percent than outside the +10 percent

Table 2. Forecast Errors by Year: All Firms, S&P 500 Firms, and Other Firms

Year/Statistic	Number of Firms	Number of Forecasts	Mean Absolute Surprise	Mean Surprise	+/–10 Percent[a]	+10 Percent[a]	–10 Percent[a]
All firms							
1984	2,109	2,246	2.525	0.795	0.697	0.311	0.386
1985	2,525	8,608	1.593	–0.667*	0.651	0.226	0.426
1986	2,580	8,506	1.773	–1.007*	0.656	0.245	0.412
1987	2,829	8,856	1.362	–0.700*	0.650	0.264	0.386
1988	2,804	9,041	1.067	–0.468*	0.620	0.269	0.351
1989	2,874	9,461	0.959	–0.537*	0.615	0.240	0.374
1990	2,890	9,627	1.034	–0.685*	0.600	0.215	0.384
1991	2,875	9,583	0.802	–0.444*	0.598	0.242	0.356
1992	3,195	10,702	0.688	–0.330*	0.557	0.261	0.296
1993	3,630	12,563	0.583	–0.230*	0.544	0.258	0.286
1994	4,193	14,213	0.494	–0.189*	0.514	0.258	0.256
1995	4,476	15,013	0.541	–0.244*	0.510	0.256	0.255
1996	4,593	11,008	0.527	–0.173*	0.501	0.260	0.241
Mean			0.916	–0.414*	0.577	0.252	0.326
Rank Correlation			–0.973*	0.489*	–0.995*	–0.038	–0.945*
S&P 500 firms							
1984	431	452	0.701	0.237	0.593	0.305	0.288
1985	443	1,743	0.748	–0.474*	0.503	0.186	0.317
1986	453	1,714	0.620	–0.250*	0.496	0.225	0.271
1987	463	1,791	0.487	–0.137*	0.487	0.245	0.243
1988	466	1,852	0.382	–0.143*	0.470	0.259	0.211
1989	473	1,842	0.427	–0.166*	0.447	0.203	0.245
1990	476	1,896	0.331	–0.113*	0.441	0.191	0.249
1991	481	1,892	0.442	–0.267*	0.467	0.189	0.277
1992	485	1,887	0.467	–0.148*	0.420	0.205	0.215
1993	486	1,983	0.345	0.027	0.409	0.220	0.189
1994	492	1,993	0.233	0.027	0.335	0.208	0.126
1995	492	1,936	0.190	–0.008	0.335	0.196	0.139
1996	494	1,314	0.310	0.002	0.318	0.177	0.141
Mean			0.418	–0.129*	0.431	0.211	0.220
Rank Correlation			–0.868*	0.357	–0.978*	–0.462	–0.819*
Other firms							
1984	1,678	1,794	2.985	0.935	0.724	0.312	0.411
1985	2,082	6,865	1.807	–0.716*	0.689	0.236	0.453
1986	2,127	6,792	2.064	–1.198*	0.697	0.250	0.447
1987	2,366	7,074	1.583	–0.843*	0.692	0.269	0.422
1988	2,338	7,189	1.244	–0.552*	0.659	0.272	0.387
1989	2,401	7,619	1.087	–0.626*	0.655	0.250	0.406
1990	2,414	7,731	1.206	–0.825*	0.639	0.221	0.417
1991	2,394	7,691	0.890	–0.488*	0.630	0.255	0.376
1992	2,710	8,815	0.735	–0.369*	0.586	0.274	0.313
1993	3,144	10,580	0.628	–0.278*	0.569	0.265	0.305
1994	3,701	12,220	0.537	–0.225*	0.543	0.266	0.277
1995	3,984	13,077	0.593	–0.279*	0.536	0.264	0.272
1996	4,099	9,694	0.557	–0.197*	0.526	0.272	0.254
Mean			1.019	–0.473*	0.608	0.260	0.348
Rank Correlation			–0.973*	0.489*	–0.984*	0.088	–0.912*

Note: Mean absolute surprise, mean surprise, and the percentage of surprises outside the three bandwidths use absolute value of earnings forecast as the deflator.

[a]Proportion of surprises outside bandwidth.

*Significant at the 5 percent level, two-tailed test.

Table 3. Forecast Errors Classified by Market Capitalization, Absolute Value of Earnings Forecast, and Analyst Following

	Number of Firms	Number of Forecasts	Mean Absolute Surprise	Mean Surprise	+/–10 Percent[d]	+10 Percent[d]	–10 Percent[d]
Market capitalization ($ millions)[a]							
<50	3,137	18,247	2.198	–1.445*	0.774	0.242	0.532
[50–100)	3,316	17,572	1.228	–0.616*	0.679	0.266	0.412
[100–500)	4,529	46,349	0.749	–0.271*	0.585	0.267	0.318
[500–3,000)	2,350	33,777	0.511	–0.096*	0.481	0.246	0.234
≥3,000	652	12,445	0.278	–0.019	0.370	0.203	0.167
Rank correlation			–1.000*	1.000*	–1.000*	–0.300	–1.000*
Absolute value of earnings forecast (cents)[b]							
<5	2,731	8,588	5.407	–2.564*	0.819	0.348	0.471
[5–10)	3,750	13,796	1.528	–0.681*	0.827	0.363	0.464
[10–25)	5,863	40,552	0.644	–0.300*	0.598	0.258	0.340
[25–50)	5,210	37,857	0.380	–0.159*	0.499	0.218	0.282
[50–100)	2,957	22,100	0.297	–0.105*	0.444	0.199	0.245
≥100	1,094	6,544	0.607	–0.250*	0.507	0.277	0.281
Rank correlation			–0.829*	0.829*	–0.771	–0.771	–0.943*
Analyst following (number of analysts)[c]							
1	6,189	35,979	1.421	–0.593*	0.707	0.293	0.414
2	5,011	22,983	1.035	–0.578*	0.629	0.272	0.358
3	3,913	15,728	0.790	–0.364*	0.581	0.251	0.330
4	3,077	11,411	0.674	–0.294*	0.544	0.246	0.298
5	2,384	8,532	0.581	–0.225*	0.519	0.241	0.278
6	1,898	6,775	0.762	–0.460*	0.482	0.217	0.266
7	1,555	5,354	0.553	–0.285*	0.465	0.207	0.258
8	1,296	4,356	0.795	–0.135	0.449	0.191	0.258
9	1,090	3,664	0.486	–0.233*	0.452	0.208	0.244
≥10	1,023	14,654	0.354	–0.126*	0.387	0.192	0.195
Rank correlation			–0.782*	0.842*	–0.988*	–0.939*	–0.988*

Note: Mean absolute surprise, mean surprise, and the percentage of surprises outside the three bandwidths use absolute value of earnings forecast as the deflator.

[a]Stock price multiplied by number of common stocks outstanding.

[b]Earnings forecast is the I/B/E/S mean forecast.

[c]Number of analysts whose forecast is included in the calculation of the I/B/E/S mean forecast.

[d]Proportion of surprises outside bandwidth.

*Significant at the 5 percent level, two-tailed test.

bandwidth, indicating that when large errors occur, analysts are more likely to overestimate earnings (optimistic bias) than to underestimate them (pessimistic bias). The two exceptions are depository institutions and insurance carriers. Perhaps these two industries are less likely than the other 12 to take big baths, which induce large negative errors and give the appearance of analyst optimism.

CONCLUSION

Using the Abel–Noser database for 1974 through 1991, Dreman and Berry argued that analyst forecasting errors are too large. Based on the I/B/E/S database for 1983 through 1996, I show that analysts' earnings forecast errors are approximately as large as Dreman–Berry documented. Thus, their results appear to have external validity.

Dreman–Berry maintained that analyst forecasting errors have increased over time. In a 1996 article, I argued that the Abel–Noser data, as summarized by Dreman–Berry, suggest precisely the opposite. In his critique of my analysis, David Dreman correctly pointed out that I did not access the data Dreman–Berry used to reach their conclusions. In this study, I used I/B/E/S data to examine five error metrics to determine whether analyst forecasting accuracy has deteriorated over time. I found that analyst forecasting errors have *decreased* significantly over time, especially for mean absolute surprise and the proportion of errors outside the +/–10 percent and –10 percent bandwidths.[11] My finding that analysts' earnings forecast errors have decreased over time is robust to firms included in as opposed to those excluded from the S&P 500.

I examined whether analyst forecasting errors differ according to certain firm-specific factors:

Table 4. Forecast Errors by Industry

SIC Code	Industry Name	Number of Firms	Number of Forecasts	Mean Absolute Surprise	Mean Surprise	+/−10 Percent[a]	+10 Percent[a]	−10 Percent[a]
13	Oil and gas extraction	73	1,681	1.663	−0.721*	0.780	0.338	0.442
20	Food and kindred products	55	1,644	0.255	−0.068*	0.361	0.166	0.195
28	Chemicals and allied products	128	3,910	0.454	−0.159*	0.422	0.189	0.233
33	Primary metal industries	63	1,619	1.267	−0.532*	0.683	0.298	0.385
35	Industrial, commercial machinery and computer equipment	128	3,958	0.794	−0.243*	0.596	0.274	0.322
36	Electronics and other equipment companies	104	2,824	0.856	−0.370*	0.556	0.237	0.319
37	Transportation equipment	66	2,096	0.820	−0.070	0.553	0.249	0.305
38	Measurement instruments; photo goods; watches	76	1,991	0.445	−0.186*	0.425	0.186	0.239
48	Communications	56	1,292	0.455	−0.076	0.429	0.202	0.227
49	Electric, gas, and sanitary services	190	6,766	0.436	−0.130*	0.560	0.261	0.299
60	Depository institutions	421	7,298	0.543	−0.336*	0.369	0.197	0.171
63	Insurance carriers	189	4,453	0.512	−0.142	0.517	0.285	0.232
67	Holding; other investment offices	82	777	0.392	−0.151*	0.539	0.175	0.364
73	Business services	78	2,111	0.540	−0.263*	0.448	0.182	0.266

Notes: Mean absolute surprise, mean surprise, and the percentage of surprises outside the three bandwidths use absolute value of earnings forecast as the deflator. To be included in Table 4, an industry must have more than 50 firms in the sample.

[a]Proportion of forecast errors (using absolute value of earnings forecast as a deflator) outside bandwidth.

*Significant at the 5 percent level, two-tailed test.

inclusion in the S&P 500, market capitalization, absolute value of earnings forecast, analyst following, and industry membership. I showed that: (1) analyst forecasting errors for S&P 500 firms are smaller than for other firms; (2) analyst forecasting errors are relatively small for firms with comparatively large market cap, absolute value of earnings forecast, and analyst following; and (3) analyst forecasting errors for firms in certain industries are substantially larger than those in other industries. Thus, depending on the nature of the firms followed by investors, analysts' earnings forecast errors may be considerably larger or smaller than average.

Dreman and Berry showed that analysts' earnings forecasts exhibit an optimistic bias. I had argued in my 1996 paper that the optimistic bias was not evident for S&P 500 firms for the period from first-quarter 1993 through third-quarter 1995. Moreover, according to I/B/E/S, the optimistic bias has not been evident for S&P 500 firms for the subsequent period, fourth-quarter 1995 through second-quarter 1997.[12]

Based on the I/B/E/S data, which include both S&P 500 and other firms, I documented an optimistic bias in analysts' quarterly earnings forecasts for all years, 1985 through 1996, and in 11 of 14 industries. I also showed that the optimistic bias in quarterly forecasts has diminished significantly over time for both S&P 500 and other firms and that it was absent for S&P 500 firms for each year from 1993 through 1996. The optimistic bias in quarterly forecasts for non-S&P 500 firms remains.[13]

NOTES

1. Because earnings forecast errors cannot be calculated when the actual or quarterly earnings forecast equals zero, these observations were omitted from the analysis. To be consistent with Dreman–Berry, I did not adjust outliers in any manner.
2. The other two definitions of earnings surprise are SURP8 and SURPC7, which respectively use the standard deviation of trailing eight-quarter actual earnings per share and the standard deviation of trailing seven-quarter changes in earnings per share.
3. Other studies have documented that managers manipulate earnings in order to report positive earnings, positive earnings growth, and/or earnings that exceed analyst expectations. When managers cannot succeed in these goals, they are likely to take a "big bath." See Lowenstein (1997).
4. For simplicity, I do not provide these results in a table.
5. These results and those that follow are based on the full I/B/E/S sample of 129,436 observations described in Table 1.
6. This suggestion was made when I presented an earlier version of this article at the 1997 Prudential Securities Quantitative Research Seminar for Institutional Investors.
7. The positive rank correlation for mean surprise indicates that the bias has become less negative (i.e., there has been a temporal reduction in the optimistic bias).
8. Such an analysis is beyond the scope of this study but is on the author's research agenda.
9. When I presented results at the 1997 Prudential Securities

Quantitative Research Seminar for Institutional Investors, I used the actual EPS as a deflator. It was suggested to me that the aberrant results for the largest EPS group may be attributable to large random shocks in the actuals. When I substituted forecasted EPS for actual EPS (as in this article), the tenor of my results was unchanged.

10. The exception is the proportion of errors outside the +10 percent bandwidth, for which the proportion of 19.2 percent for the analyst following of ≥10 slightly exceeds the proportion of 19.1 percent for the analyst following of 8.
11. The exception is that the percentage of errors outside the +10 percent bandwidth has not decreased significantly for either the entire I/B/E/S sample or the non-S&P 500 subsample.
12. According to information provided to me by I/B/E/S, the mean surprises for S&P 500 firms for these seven quarters (sample sizes are in parentheses) are 1.7 percent (488), 2.4 percent (492), 2.6 percent (490), 2.4 percent (490), 1.9 percent (481), 3.3 percent (492), and 2.2 percent (491). The optimistic bias is still present for S&P 500 firms for annual forecasts.
13. I am grateful to Deres Tegenaw for providing me with excellent research assistance.

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Trends in analyst earnings forecast properties

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Abstract

Forecast dispersion, error, and optimism are computed using 120,022 quarterly observations from 1990 to 2001. Forecast dispersion, error, and optimism all decrease steadily over the sample period, with loss firms showing an especially striking decrease. By the end of the sample period, dispersion and error differences between profit and loss firms are relatively minor, optimism for loss firms is around an unbiased 50%, and pessimism dominates profit firms. Additionally, loss firm earnings appear more difficult to forecast. The reduction in dispersion, error, and optimism does not appear fully attributable to earnings management, earnings guidance, or earnings smoothing. The trends are consistent with increased litigation concerns.

JEL classification: D84; G14; G24
Keywords: Earnings forecasts; Analysts; Earnings management; Forecast dispersion; Forecast accuracy

1. Introduction

A major responsibility of analysts is to make earnings forecasts. Professionals, such as investment bankers, financial advisors, and stockbrokers, rely on these forecasts to make their decisions, as do many individual investors. The forecasts serve as critical inputs into stock valuation models. Earnings announcement period returns are influenced by the forecasts (e.g., Imhoff & Lobo, 1992), and forecast dispersion is even related to monthly or annual stock returns (Ang & Ciccone, 2001; Diether, Malloy, & Scherbina, 2002; Dische, 2002). Forecasts are now publicly available on many investment-related web sites, providing free access to millions of investors all over the world.

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For a long period of time, the ability of analysts to forecast earnings was questioned. Analysts were biased some argued, optimistic and unresponsive to earnings changes (Abarbanell & Bernard, 1992; DeBondt & Thaler, 1990). They tended to herd, making forecasts or recommendations similar to other analysts (Hong, Kubik, & Solomon, 2000; Olsen, 1996; Stickel, 1990; Trueman, 1994; Welch, 2000). They were better than time-series earnings estimates, but only slightly (Fried & Givoly, 1982; O'Brien, 1988).

Recent studies have found that analyst forecasts have changed, perhaps even improved. Analysts have reduced both the size of their forecast errors and their optimism (Brown, 1997; Matsumoto, 2002; Richardson, Teoh, & Wysocki, 2001). Unfortunately for the analysts, many attribute this trend, not to better forecast accuracy, but to increases in earnings guidance, management, or smoothing (e.g., Degeorge, Patel, & Zeckhauser, 1999; Matsumoto, 2002).

The purpose of this study is twofold, both to document trends in forecast properties and to differentiate among theories as to why the trends exist. Several trends are investigated; some revisited, some new: (1) the trends of dispersion, error, and optimism; (2) the trend of wrongly forecasted profits or losses; (3) the trend of naïve forecast performance versus analyst forecast performance; (4) the trend of earnings volatility; and (5) the trend of Street versus GAAP earning differences. In addition, the influence of Regulation FD on the trends is examined. Quarterly data is used during a 1990 to 2001 sample period. As previous research has shown that analysts have greater difficulty forecasting the earnings of firms with losses (Brown, 2001; Butler & Saraoglu, 1999; Ciccone, 2001; Dowen, 1996; Dreman & Berry, 1995), firms with profits and losses are separated and examined independently in much of the testing.[1]

There are several possible explanations for changes in forecast properties: legal liability (e.g., Skinner, 1994), earnings guidance (e.g., Matsumoto, 2002), earnings management (e.g., Degeorge et al., 1999), earnings smoothing (consistent with Bartov, 1993), or information flow improvements (consistent with Asthana, 2003). The testing investigates the validity of these reasons.

The results are quite remarkable. Forecast properties have undergone an extraordinary change, perhaps best called a transformation, during the sample period. Forecast dispersion and error both decrease throughout the sample period, with most of the decrease due to loss firm forecasts. Although analysts still do not forecast loss firms with the same degree of accuracy as profit firms, the differences in forecasting performance are steadily eroding.

Optimism also decreases as analysts moved from being optimistically biased to being pessimistically biased during the sample period. The pessimism associated with profit firms is astonishing. Near the end of the sample period, almost three quarters of the

[1] Several related studies exist. Brown (1997), Richardson et al. (2001), and Matsumoto (2002) all show a decreasing trend in signed earnings surprise or optimism, although they do not separate firms by profitability. Gu and Wu (2003) evaluate forecast differences between profit and loss firms but do not examine trends in performance. Dreman and Berry (1995) and Butler and Saraoglu (1999) do separate firms by profitability while examining trends, but both rely on sample periods ending in 1991. Brown (2001) uses the signed, earnings surprise of the last forecast made prior to the earnings release date to examine shifts in the trend of the median surprise for profit and loss subsamples.

quarterly forecasts for profit firms are pessimistic. Analysts still tend to be optimistic toward loss firms, but this optimism has decreased dramatically over the sample period, hovering around an unbiased 50% at the end of the period. The decrease in the optimistic biases is so pronounced that the still-lingering legend of analyst earnings optimism (e.g., Easterwood & Nutt, 1999; Gu & Wu, 2003) is clearly no longer true, even for loss firms. If anything, analysts have a new concern: earnings pessimism for profit firms.

Additional results show that analysts have gotten much better at predicting the sign of earnings when firms report losses. Moreover, forecasting loss firm earnings appears to be much more difficult than forecasting profit firm earnings. Given this difficulty, analysts actually seem to provide greater value to the market when forecasting for loss firms.

Finally, the results suggest that the trends in forecast properties are unlikely to be fully attributable to earnings guidance, management, or smoothing. Firms unlikely to manage earnings—those with negative surprises, earnings declines, and losses—experience similar reductions in dispersion and error as the sample of all firms. So do firms considered unlikely to be guiding firms toward a specific earnings target, those with high dispersion. Furthermore, Street versus GAAP earnings differences and earnings volatility do not affect the results. The trends in forecast properties are consistent with litigation concerns, especially those surrounding loss reporting. In addition, although not specifically tested, analysts, aided by new information technology, may have simply improved in their forecasting abilities.

2. Forecast property changes

One of the most prominent explanations for the changing trends in forecast properties centers on earnings management. In the financial press, managers are often thought to play an "earnings game," manipulating reported earnings (and hence the surprise) to reap various benefits: increased stock prices, favorable publicity, and bonuses (Vickers, 1999). Fox (1997) tells of a Microsoft 1997 quarterly earnings release in January, the 41st time in 42 consecutive quarters that Microsoft met or beat the Wall Street consensus. The earnings game is often considered dangerous: when played long-term prospects are sacrificed by concern with short-term profits. Corporate decisions are altered, accounting rules are stretched, and investors lose faith in both financial statements and stock prices (Collingwood, 2001).

Academics have intensively investigated the issue of earnings management. Burgstahler and Dichev (1997) and Degeorge et al. (1999) find that firms manage earnings to meet analyst expectations, avoid losses, and avoid earnings declines. These studies mention several reasons why executives manage earnings, including increased job security, increased bonuses, and bolstered investor interest. Furthermore, anecdotal evidence suggests that firms like the favorable publicity of positive surprises, profits, and earnings increases. Of the three objectives identified by Degeorge, Patel, and Zeckhauser, the positive profit objective proves predominant. However, missing a consensus earnings estimate can be very costly to a firm. For example, Skinner and Sloan (2002) find that, all else equal, the price decline after a negative surprise is greater than the price increase following a positive surprise.

Another way of managing earnings entails "smoothing" or making earnings less volatile through time (e.g., Bartov, 1993). There are several theories that attempt to explain this behavior. Healy (1985) and Holthausen, Larcker, and Sloan (1995) find smoothed earnings are related to management bonus arrangements. Degeorge et al. (1999) use these findings to argue that managers may reduce high earnings levels to make future earnings objectives easier to meet. Fudenberg and Tirole (1995) argue that managers will boost earnings in bad times to increase the probability of retaining their jobs. Trueman and Titman (1988) believe that firms smooth earnings to lower their perceived bankruptcy risk and thus lower their cost of debt.

A cheaper way of playing the earnings game involves forecast guidance. Firms guide analysts toward a pessimistic target and then beat that target (Matsumoto, 2002), an easy way to garner favorable publicity.

An additional perspective on earnings guidance is rooted in legal liability issues. Firms face scrutiny when reporting large, unexpected losses. The consequent stock price decrease angers investors, who then might sue the firm for damages, consistent with Skinner (1994, 1997). Kasznik and Lev (1995) provide support for this argument by showing that firms increased their tendency to warn investors of impending losses. By warning of losses, firms are not necessarily playing an earnings game. As such, guiding analysts toward pessimistic targets and warning analysts of losses, although related, are considered two distinct concepts in this study.

Simpler explanations also exist to explain forecasting trends. For example, an alternative viewpoint looks at data availability and the information revolution, consistent with Asthana (2003). Forecasting techniques might be improving, aided in part by more precise and timelier economic information. Communications channels between firm managers and analysts may be better. Perhaps even the recent proliferation of freely available financial information on the Internet makes analysts more careful as they strive to add value and provide information above and beyond what is known by individual investors.

3. Data and methodology

The First Call summary database is used to obtain the forecast properties. Quarterly forecasts are used to present all results. The results using annual forecasts are similar to the quarterly results and do not require separate analysis. The last mean forecast available prior to the fiscal period end is used as the consensus forecast. All conclusions are similar if median forecasts are used instead of the mean forecasts or if the last mean forecasts prior to the earnings release are used instead of the last mean forecasts prior to fiscal period end.

Forecast dispersion is defined as the standard deviation of the forecasts divided by the absolute value of the mean forecast. This measure requires at least two forecasts.[2] Forecast error is defined as the difference between the actual earnings and the mean forecasted

[2] Although the procedure sharply reduces the sample size, the results for dispersion are similar if only companies with five or more analysts are included.

earnings, divided by the actual earnings. The absolute value is taken to obtain the final error number. A "raw error" is also computed as the absolute value of the difference between actual and forecasted earnings (i.e., the error is not deflated).[3] A forecast is considered optimistic if the mean forecast is greater than the corresponding actual earnings. The error and optimism measures require at least one forecast.

Many studies deflate the forecast properties by the stock price rather than the deflators described above. Thus, as a check, trends in dispersion and error are reexamined using price at the beginning of the fiscal year as the deflator. These results are qualitatively similar to the presented results, although the trends are not quite as obvious.[4]

Forecast dispersion is sometimes thought to signify herding. With this interpretation, low dispersion would be undesirable as it suggests greater herding. However, in this study, low dispersion is considered a desirable property. At least two reasons suggest this is true: (1) firms with losses or earnings declines, potential candidates to hide bad information, tend to have highly dispersed forecasts in previous studies (Ciccone, 2001), and (2) the high positive correlation between dispersion and error.[5]

An important component of this research is the separation of firms with losses and profits. A loss is defined as when the actual earnings per First Call are less than zero. A profit is defined as when actual earnings are greater than or equal to zero. First Call earnings, frequently referred to as "Street" or "operating" earnings (among other names), are often different from earnings under generally accepted accounting principles or GAAP (Abarbanell & Lehavy, 2000; Bradshaw & Sloan, 2002). The results are similar if GAAP earnings are used to determine profitability. The Compustat database is used to obtain GAAP earnings.

To alleviate problems with small denominators, a firm with a divisor less than US$0.02 in absolute value terms has the problem divisor set to US$0.02. Two procedures are used to reduce the influence of large observations. Firms with dispersion or error numbers greater than 10 and firms with earnings per share greater than an absolute value of US$20 are eliminated from their respective sample. Combined, the two procedures eliminate a total of 220 quarterly observations with no effect on the conclusions.

The final sample includes the years 1990 through 2001, a 12-year or 48-quarter period.[6] The total sample includes 120,022 firm quarters: 94,194 with profits and 25,828 (21.5%) with losses. The number of observations varies by the forecast property being examined.

[3] The raw error, often called the "earnings surprise" (although usually with the sign or direction of the error), is important because this number is often reported by the news media. It is important to note that "error" and "raw error" have two distinct meanings in this study.

[4] Using price as a deflator, average profit firm dispersion decreases from 0.0027 in the early (1990–1995) sample period to 0.0015 in the later sample period (1996–2001). Loss firm dispersion decreases from 0.0128 to 0.0069. Profit firm error decreases from 0.0052 to 0.0041, while loss firm error decreases from 0.0409 to 0.0333. All differences are significant with 99% confidence.

[5] To illustrate the latter point, the correlation between the dispersion and error is computed as 0.22 (0.24 if a log transform is performed). In a related test, every quarter each firm is placed into 1 of 10 portfolios based on its ranking of dispersion and 1 of 10 portfolios based on its ranking of error. The correlation between the group placement (1–10) is then computed. The correlation between the dispersion and error groupings is .47.

[6] The year 1990 contains considerably less sample firms than the other 11 years. Caution is thus recommended when evaluating the 1990 data.

The dispersion measure has the fewest number of observations: 84,919 quarterly observations.

Portfolio analyses are used to communicate the results in an easily accessible manner. The included tables present the results year-by-year and also during two sample periods: an "early" sample period from 1990 through 1995 and a "later" sample period from 1996 through 2001. Each period contains half the sample years. In addition, regression models controlling for size and book-to-market ratio are used to support the major conclusions reached.

4. Forecasting trends

Table 1 presents, by year, the forecast properties and maximum number of observations (recall there are sample size differences among the various properties). Dispersion, error, raw error, and optimism all steadily decrease throughout the sample period. The trend for optimism is interesting as the forecasts changed from being optimistic more than 50% of the time in the first couple of sample years to being optimistic less than 50% of the time after 1992. The amount of optimism continues to decrease during the sample period, reaching a low of 34.27% in 2000.

Table 1
Forecast dispersion, error, and optimism

	Quarterly forecasts				
	Maximum number of observations	Dispersion	Error	Raw error	Percent optimistic
All years	120,022	0.22	0.44	0.09	40.27
1990–1995	40,949	0.27	0.48	0.11	45.90
1996–2001	79,073	0.20	0.42	0.09	37.36
Difference		0.07*	0.06*	0.02*	8.54*
1990	1373	0.31	0.58	0.16	57.70
1991	2929	0.38	0.59	0.15	53.77
1992	6497	0.30	0.46	0.11	46.36
1993	8411	0.26	0.46	0.12	46.64
1994	10,249	0.25	0.46	0.10	43.33
1995	11,490	0.24	0.47	0.09	43.88
1996	14,002	0.23	0.44	0.09	39.27
1997	14,942	0.19	0.41	0.08	38.86
1998	15,184	0.20	0.41	0.08	38.71
1999	13,638	0.20	0.43	0.09	34.95
2000	12,314	0.17	0.42	0.10	34.27
2001	8993	0.21	0.42	0.09	37.46

This table reports mean analyst quarterly forecast properties over the sample period 1990 through 2001. Dispersion is defined as the standard deviation of the quarterly forecasts divided by the absolute mean forecast. Raw error is defined as the absolute value of the actual earnings less the forecasted earnings. Error is defined as the absolute value of the actual earnings less the forecasted earnings, divided by the absolute actual earnings. A firm's forecast is considered optimistic if the mean forecast is greater than the corresponding actual earnings. As the sample size varies by the forecast property in question, the maximum number of observations is reported.

* Difference is significantly different from zero with 99% confidence.

Table 2 shows the same forecast properties after separating firms by profitability. The dispersion and error of loss firms is considerably greater than the dispersion and error of profit firms. This occurs in every sample year and, although not tabulated, in every sample quarter. However, loss firms show greater reductions in dispersion and error throughout the sample period. The average dispersion of loss firms decreases from a high of 1.12 in 1990 to 0.30 in 2000 and 0.33 in 2001. Thus, the typical forecast dispersion of a loss firm today is roughly a quarter of what it was just 10 years ago. The story is similar for forecast error. The mean forecast error of loss firms decreases from a high of 1.16 in 1990 to 0.63 in 2000 and 0.55 in 2001. The error reduction for profit firms is not nearly as large, decreasing from a high of 0.48 in 1991 to 0.33 in 2000 and 0.35 in 2001.

The first two charts in Fig. 1 show the forecast dispersion and error by year and profitability. The figure provides a nice illustration of the eroding dichotomous forecasting ability of analysts. Clearly, analysts are narrowing the gap in their performance between profit and loss firms.

Table 2 also presents statistics for the mean raw error. Similar to the previous results, improvement in the raw error numbers occurs regardless of profitability, but the improvement is especially large for loss firms. For example, the raw error of loss firms decreases by more than half, from an average of US$0.48 in 1991 to US$0.21 in 2000 and US$0.16 in 2001.

The last columns of Table 2 show the percentage of optimistic forecasts. In the early sample period, analysts are overwhelmingly optimistic toward loss firms, more than 75% of time. The optimism remains above 70% until 1997 when it drops to 67.66%. From

Table 2
Forecast dispersion, error, raw error, and optimism by profitability

	Dispersion		Error		Raw error		Percent optimistic (negative surprise)	
	Profit	Loss	Profit	Loss	Profit	Loss	Profit	Loss
All quarters	0.15	0.53	0.35	0.78	0.06	0.23	33.63	64.48
1990–1995	0.18	0.88	0.37	1.02	0.07	0.33	40.32	75.93
1996–2001	0.13	0.43	0.33	0.70	0.05	0.20	29.76	60.70
Difference	0.05*	0.45*	0.04*	0.32*	0.02*	0.13*	10.56*	15.23*
1990	0.19	1.12	0.47	1.16	0.10	0.49	52.97	85.42
1991	0.24	1.11	0.48	1.09	0.08	0.48	48.40	78.44
1992	0.21	0.94	0.37	0.95	0.07	0.34	40.91	76.43
1993	0.17	0.91	0.37	0.96	0.08	0.34	41.67	74.80
1994	0.17	0.80	0.36	0.99	0.06	0.30	37.82	73.54
1995	0.16	0.81	0.35	1.11	0.06	0.28	37.54	76.75
1996	0.15	0.70	0.34	0.86	0.05	0.26	32.06	70.90
1997	0.12	0.50	0.32	0.78	0.05	0.22	31.58	67.66
1998	0.13	0.47	0.32	0.71	0.04	0.19	30.68	65.21
1999	0.14	0.39	0.33	0.70	0.05	0.20	26.84	58.42
2000	0.13	0.30	0.33	0.63	0.05	0.21	26.63	51.97
2001	0.15	0.33	0.35	0.55	0.05	0.16	29.44	53.12

This table reports mean analyst quarterly forecast properties sorted by profitability over the sample period 1990 through 2001. A profit occurs when actual quarterly earnings are greater than or equal to zero. A loss occurs when actual quarterly earnings are less than zero. See Table 1 for variable definitions.

* Difference is significantly different from zero with 99% confidence.

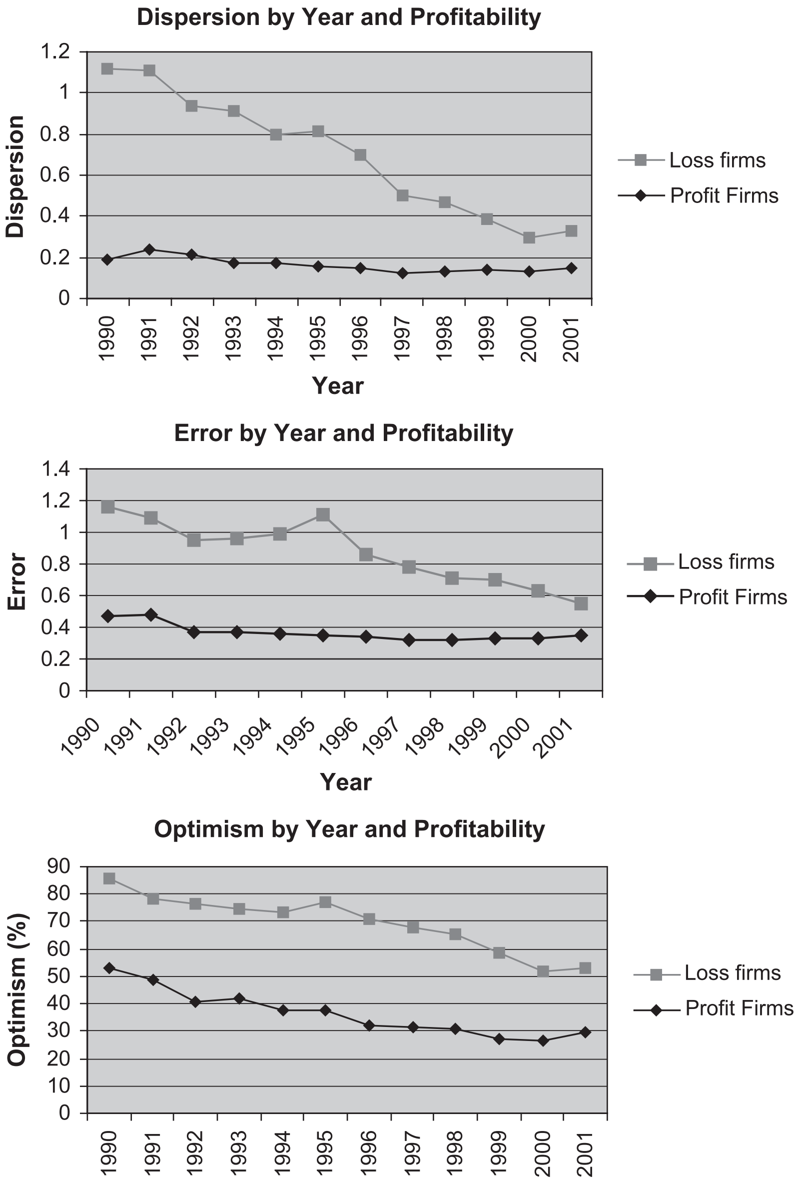

Fig. 1. Forecast properties by year and profitability.

there, the optimism continues to decrease, dropping to an almost unbiased 51.97% in 2000 and 53.12% in the 2001. For profit firms, optimism on average vanishes in 1991 and continues to decrease steadily throughout the sample period. By the end of the sample period, optimism is under 30%. The last chart in Fig. 1 illustrates this trend of decreasing optimism for both profit and loss firms.

Although the testing focuses on realized actual earnings to determine profitability, the results from Table 2 are repeated using expected earnings to determine profitability. Firms are resorted into profit and loss portfolios based on the mean forecast at fiscal year end. These results (not tabulated) are qualitatively similar to the Table 2 results, although average dispersion, error, and optimism are higher for expected profit firms (versus actual profit firms) and lower for expected loss firms. Optimism actually drops below 50% for expected loss firms during the last three sample years: 1999, 2000, and 2001. Related testing is performed on Table 6.

Regression models are utilized next to control for variables aside from profitability that influence forecasts. Previous studies have shown that size and growth prospects (growth indicated by book-to-market ratio) affect the information environment (e.g., Atiase, 1985; Ciccone, 2001).[7]

To test, two sets of regression models are used. The first set of regressions is employed to confirm the trend of lower dispersion and error during the sample period. These models use dispersion and error as the dependent variables and size, book-to-market ratio, a loss dummy variable, and year dummy variables as the independent variables. The Compustat database is used to gather the size and book-to-market ratio data. Size is defined as price times shares, computed at the beginning of the fiscal year. Book-to-market ratio is defined as beginning of fiscal year equity (Compustat item A216) divided by size. Logarithms of size and book-to-market ratio are used in the regressions. The loss dummy variable equals one if the actual First Call earnings are negative and zero otherwise. The year dummy variables equal one if the forecast is from the corresponding year and zero otherwise. The first year dummy variable corresponds to 1991, leaving 1990 as the base year. This specification is as follows for firm i during year t, quarter q.

$$\begin{aligned}\text{Forecast property}_{i,t,q} = {} & a + b_1\ \log(\text{size})_{i,t} + b_2\ \log(\text{b/m})_{i,t} \\ & + b_3\ \text{loss dummy}_{i,t,q} + b_4\ \text{year 1991 dummy}_{i,t} + \ldots \\ & + b_{14}\ \text{year 2001 dummy}_{i,t} + e_{i,t,q} \qquad (1)\end{aligned}$$

Table 3 presents the results of these regressions. Although size, book-to-market ratio, and especially losses affect the forecasts, the significant, negative values on the year dummy variables tend to increase in magnitude over the sample period. For example, using error as the dependent variable, the coefficient of the 1992 year dummy is -0.11 (indicating an average decrease of -0.11 relative to the 1990 base year), while that of the 2001 year dummy is -0.23 (indicating an average decrease of -0.23 relative to the 1990 base year). These results confirm the trends revealed in the portfolio results.

In the second set of regressions, models are employed annually from 1990 through 2001 to confirm the erosion of differences between profit and loss firm forecasts.

[7] The size of the analyst following is also included in separate regressions with no effect on the conclusions. Analyst following is not included in the presented results because of its strong correlation to size, thus blurring the relation between size and the forecast properties.

Table 3
Regression results using year dummy variables

	Dispersion		Error	
	Coefficient	*t* Value	Coefficient	*t* Value
Intercept	0.24	9.21	1.09	30.61
log (size)	0.01	2.17	– 0.04	– 22.61
log (book/market)	0.06	21.55	0.06	15.95
Loss dummy	0.42	82.48	0.43	61.21
1991	0.07	2.78	– 0.02	– 0.60
1992	0.00	0.21	– 0.11	– 3.71
1993	– 0.03	– 1.21	– 0.13	– 4.42
1994	– 0.04	– 1.99	– 0.13	– 4.47
1995	– 0.05	– 2.33	– 0.12	– 4.33
1996	– 0.05	– 2.45	– 0.15	– 5.34
1997	– 0.11	– 5.40	– 0.19	– 6.86
1998	– 0.11	– 5.44	– 0.19	– 6.82
1999	– 0.13	– 6.23	– 0.19	– 6.67
2000	– 0.15	– 7.61	– 0.20	– 7.31
2001	– 0.17	– 8.27	– 0.23	– 8.29
N	75,337		105,287	

This table reports the results of a regression model. Either forecast dispersion or error is the dependent variable. The independent variables are the logarithm of size (price times shares) in thousands, the logarithm of book-to-market value (equity/size), a loss dummy equal to one if the actual quarterly First Call earnings are below zero and equal to zero otherwise, and year dummy variables spanning 1991 through 2001 equal to one if the quarterly forecast is from the corresponding year. The regression model is below:

$$\text{Forecast property}_{i,t} = a + b_1\log(\text{size})_{i,t} + b_2\log(\text{b/m})_{i,t} + b_3\text{ loss dummy}_{i,t} + b_4\text{ year 1991 dummy}_{i,t} + \ldots + b_{14}\text{ year 2001 dummy}_{i,t} + e_{i,t}$$

Dispersion and error are the dependent variables, while size, book-to-market ratio, and a loss dummy variable are the independent variables. The annual model appears below:

$$\text{Forecast property}_{i,q} = a + b_1\ \log(\text{size})_i + b_2\log(\text{b/m})_i + b_3\text{ loss dummy}_{i,q} + e_{i,q} \tag{2}$$

The results of these regressions appear on Table 4. Once again, the portfolio results are confirmed. For example, using dispersion as the dependent variable, the coefficient on the loss dummy variable decreases sharply over the sample period, dropping from 0.83 and 0.86 in 1990 and 1991, respectively, to 0.20 in 2001.

Table 5 shows the percentage of analysts forecasting the wrong sign. In the early sample period using the annual earnings, analysts forecast profits for firms with actual losses 33.95% of the time. This number is far greater than the reverse. In the early sample period, analysts forecast losses for firms with actual profits just a little over 1% of the time. Although over the sample period, there is no improvement in predicting profits for actual profit firms (profit prediction actually gets worse), the improvement for loss firms is rather extraordinary. At the end of the sample period, profits are forecasted for loss firms only 14.24% of the time in 2000 and 12.20% of the time in 2001, consistent with the increasing tendency of firms to warn of losses.

Table 4
Annual regression results using loss dummy variables

Year	Dispersion									
	Coefficient				t Value				F value	R^2 (adjusted)
	Intercept	Size	B/M	Loss dummy	Intercept	Size	B/M	Loss dummy		
1990	− 0.14	0.03	0.12	0.83	− 0.76	2.22	3.41	12.94	65.43	0.21
1991	0.14	0.01	0.12	0.86	0.88	1.11	4.97	17.19	115.18	0.18
1992	0.10	0.01	0.11	0.73	1.80	0.96	6.86	22.20	189.14	0.14
1993	0.20	0.00	0.06	0.73	2.61	0.10	4.29	27.04	258.12	0.14
1994	0.20	0.00	0.07	0.63	2.93	0.31	6.51	27.26	268.99	0.12
1995	0.15	0.00	0.04	0.66	2.39	0.65	4.10	31.80	354.31	0.13
1996	0.37	− 0.01	0.04	0.62	6.81	− 3.34	5.02	35.40	455.72	0.14
1997	0.25	− 0.01	0.04	0.38	5.85	− 2.05	5.95	29.54	324.43	0.09
1998	0.13	0.00	0.05	0.34	3.08	1.08	6.67	28.82	299.31	0.08
1999	0.08	0.01	0.06	0.29	1.73	2.43	10.13	23.20	218.10	0.07
2000	0.16	− 0.00	0.04	0.22	3.66	− 0.09	7.17	18.48	126.99	0.05
2001	− 0.08	0.02	0.04	0.20	− 1.77	5.29	6.51	16.95	103.18	0.05
Year	Error									
	Coefficient				t Value				F value	R^2 (adjusted)
	Intercept	Size	B/M	Loss dummy	Intercept	Size	B/M	Loss dummy		
1990	0.77	− 0.02	0.09	0.51	3.09	− 0.88	1.93	5.80	14.98	0.04
1991	1.16	− 0.05	0.09	0.50	6.97	− 3.71	3.12	8.96	45.28	0.05
1992	0.81	− 0.03	0.07	0.60	7.77	− 3.71	4.01	17.03	118.41	0.06
1993	1.02	− 0.05	0.09	0.54	10.88	− 6.21	5.40	17.58	146.80	0.06
1994	1.18	− 0.06	0.07	0.58	13.82	− 8.91	4.86	21.00	213.69	0.07
1995	1.06	− 0.05	0.04	0.68	12.83	− 8.18	2.41	25.27	285.53	0.08
1996	1.13	− 0.06	0.04	0.54	16.23	− 10.77	3.72	24.18	287.19	0.07
1997	0.95	− 0.05	0.03	0.41	14.56	− 9.22	3.10	21.17	228.30	0.05
1998	0.86	− 0.04	0.08	0.35	13.78	− 7.35	7.46	19.78	214.93	0.05
1999	0.78	− 0.03	0.07	0.37	11.79	− 5.87	6.69	19.09	192.21	0.05
2000	0.76	− 0.03	0.06	0.35	11.29	− 5.70	7.11	18.84	168.52	0.04
2001	0.70	− 0.02	0.06	0.19	8.91	− 3.94	4.90	9.36	58.84	0.02

This table reports the results of an annual regression model, run every sample year from 1990 through 2001. Either forecast dispersion or error is the dependent variable. The independent variables are the logarithm of size (price times shares) in thousands, the logarithm of book-to-market value (equity/size), and a loss dummy equal to one if the actual quarterly First Call earnings are negative and zero otherwise. The regression model is below:

$$\text{Forecast property}_i = a + b_1 \log(\text{size})_i + b_2 \log(\text{b/m})_i + b_3 \text{ loss dummy}_i + e_i$$

To directly examine forecast performance when actual profitability differs from forecasted profitability, firms are separated into four portfolios based on actual versus expected profits or losses. For example, one portfolio includes firms with expected profits that report actual losses, while another includes firms with expected losses reporting actual losses. Mean dispersion and error are computed for each of the four portfolios. The results are presented in Table 6.

In an unsurprising result, firms with expected and actual profits have the lowest dispersion and error. Interestingly, however, firms with expected and actual losses have the

Table 5
Percentage of firms with wrong sign mean forecasts

	Quarterly forecasts	
	Forecasted loss, actual profit (%)	Forecasted profit, actual loss (%)
All years	1.79	23.31
1990–1995	1.22	33.95
1996–2001	2.11	19.80
Difference	− 0.89*	14.15*
1990	0.89	44.79
1991	1.58	35.11
1992	1.38	30.79
1993	1.04	31.85
1994	1.18	32.15
1995	1.27	37.08
1996	1.72	29.57
1997	1.73	24.28
1998	1.86	21.42
1999	2.52	19.59
2000	2.49	14.24
2001	2.89	12.20

This table reports the percentage of analysts forecasting the wrong sign (e.g., forecasting a profit when an actual loss is eventually reported) over the sample period 1990 through 2001. All numbers are in percent.

*Difference is significantly different from zero with 99% confidence.

second lowest dispersion and error, while the two portfolios containing firms with actual profitability different from expected profitability have the highest dispersion and error. In addition, although error does decrease in the portfolio of expected loss, actual loss firms throughout the sample period, the trend is not nearly as clear and the differences not nearly as large compared with the Table 2 results. These results, combined with the results from Table 5, suggest that a large portion of the decrease in loss firm error comes from two sources: (1) improvement in the error of expected profit, actual loss firms and (2) the higher percentage of losses being predicted (i.e., less expected profit, actual loss firms).

The final testing in this section examines the error and optimism of the mean analyst forecast versus the error and optimism of a "naïve" forecast, the actual First Call earnings in the prior fiscal period.[8] This test addresses several important issues. It provides a measure of the amount of value that analysts provide over and above a forecasting method simple enough to be employed by even the most unsophisticated of individual investors. The test also provides a standard by which to measure earnings predictive difficulty. Firms with accurate naïve forecasts can be thought of as having earnings that are relatively easy to predict. Related to prediction difficulty, the test also somewhat controls for earnings

[8] For the tabulated quarterly results, the naïve model compares the current quarter earnings with the prior quarter earnings (e.g., third quarter 1992 compared with second quarter 1992). To control for earnings seasonality, the prior year quarterly earnings are also used to compute naïve forecasts (e.g., second quarter 1993 compared with second quarter 1992). However, because these naïve forecasts are less accurate than the naïve forecasts using the prior quarter earnings, the results are presented using the more accurate prior quarter naïve forecasts. (Using all sample firms, the average naïve error is 0.82 using prior year quarterly earnings and 0.72 using prior quarter earnings.) The results using the prior year naïve forecasts are similar although analyst superiority is greater.

Table 6
Dispersion and error by expected and actual profitability

Expected	Quarterly forecasts							
	Dispersion				Error			
	Profit	Profit	Loss	Loss	Profit	Profit	Loss	Loss
Actual	Profit	Loss	Profit	Loss	Profit	Loss	Profit	Loss
All years	0.13	0.93	1.07	0.42	0.31	1.97	2.38	0.42
1990–1995	0.16	1.17	1.37	0.74	0.35	2.06	2.59	0.50
1996–2001	0.12	0.82	0.98	0.35	0.29	1.91	2.31	0.40
Difference	0.04*	0.35*	0.39*	0.39*	0.06*	0.15*	0.28*	0.10*
1990	0.19	1.31	0.67	0.98	0.47	2.01	2.09	0.49
1991	0.23	1.30	0.99	1.01	0.44	1.97	2.90	0.62
1992	0.19	1.38	2.00	0.76	0.34	2.06	2.76	0.46
1993	0.16	1.24	1.33	0.76	0.35	2.03	2.44	0.46
1994	0.15	1.08	1.30	0.68	0.33	2.07	2.57	0.49
1995	0.14	1.04	1.26	0.69	0.32	2.12	2.55	0.51
1996	0.13	1.04	1.22	0.57	0.30	1.89	2.25	0.43
1997	0.11	0.84	1.00	0.40	0.28	1.94	2.42	0.41
1998	0.11	0.75	1.08	0.40	0.28	1.88	2.11	0.39
1999	0.12	0.73	0.94	0.32	0.28	1.90	2.38	0.41
2000	0.11	0.68	0.84	0.24	0.28	1.98	2.18	0.41
2001	0.13	0.77	0.77	0.27	0.29	1.93	2.54	0.37

This table reports mean analyst quarterly forecast properties sorted by expected and actual profitability over the sample period 1990 through 2001. An actual profit occurs when actual quarterly earnings are greater than or equal to zero, while an actual loss occurs otherwise. A forecasted profit occurs when mean forecasted earnings are greater than or equal to zero, while a forecasted loss occurs otherwise. See Table 1 for variable definitions.

* Difference is significantly different from zero with 99% confidence.

volatility or earnings management (see also next section). Firms with managed or less volatile earnings would probably have more accurate naïve forecasts.

Error, raw error, and optimism are computed using both the analyst forecasts and the naïve forecasts for all sample firms having the required prior period actual earnings information. The sample size is 103,778 firm-quarter observations: 82,203 with profits and 21,575 (20.8%) with losses.

Table 7 reports the results for two forecast properties: error and raw error. For each sample firm, the analyst forecast error is subtracted from the naïve forecast error. For example, if the naïve forecast error is 0.90 and the analyst forecast error is 0.40, then the difference is 0.50. The mean of these differences is computed and reported in the table. Note that in the table, positive numbers indicate analyst superiority, and the larger the difference, the more accurate analyst forecasts are versus naïve forecasts.

Several findings are important. Analyst forecasts are considerably more accurate in every sample year indicating that analysts provide a great deal of value in forecasting earnings versus a simple naïve model. However, they provide more value when forecasting the earnings of loss firms. For example, for all years, the difference between the naïve and analyst error is on average 0.26 for profit firms and 0.45 for loss firms.

Analysts have also slightly increased the value of their forecasting during the sample period, particularly for loss firms. For example, in the early sample period, the analysts are

Table 7
Differences between naïve and analyst forecasts: error and raw error

	Quarterly forecasts					
	Error differences (naïve error – analyst error)			Raw error (RE) differences (naïve RE – analyst RE)		
	All	Profit	Loss	All	Profit	Loss
All years	0.30	0.26	0.45	0.08	0.07	0.08
1990–1995	0.26	0.24	0.39	0.07	0.07	0.07
1996–2001	0.32	0.27	0.47	0.08	0.08	0.08
Difference	– 0.06*	– 0.03*	– 0.08*	– 0.01*	– 0.01*	– 0.01
1990	0.27	0.23	0.48	0.07	0.05	0.18
1991	0.19	0.17	0.32	0.08	0.08	0.11
1992	0.29	0.26	0.45	0.08	0.08	0.06
1993	0.26	0.24	0.38	0.05	0.05	0.06
1994	0.27	0.25	0.35	0.07	0.07	0.06
1995	0.26	0.24	0.40	0.08	0.08	0.08
1996	0.32	0.28	0.55	0.08	0.08	0.07
1997	0.30	0.27	0.46	0.08	0.08	0.07
1998	0.36	0.29	0.59	0.09	0.09	0.10
1999	0.33	0.30	0.44	0.09	0.09	0.08
2000	0.31	0.29	0.39	0.08	0.09	0.07
2001	0.25	0.17	0.38	0.08	0.08	0.08

This table reports the difference between naïve forecast errors and analyst forecast errors over the sample period 1990 through 2001. Analyst forecast error and raw error are defined as in Table 1. Naïve forecast raw error is defined as the absolute value of actual quarterly earnings less the previous quarter's actual earnings. Naïve forecast error deflates this number by the absolute actual quarterly earnings. The reported differences are computed as the naïve error less the analyst error. Thus, positive differences indicate analyst superiority (i.e., lower errors): the higher the difference, the greater the analyst superiority.

* Difference is significantly different from zero with 99% confidence.

superior by 0.39 in predicting error. In the later sample period, this superiority increases to 0.47.

Although not tabulated, naïve forecasts for loss firms are markedly less accurate versus naïve forecasts for profit firms. The mean quarterly naïve forecast error is 0.60 for profit firms and 1.22 for loss firms. The differences remain fairly stable across the sample period. This suggests that loss firm earnings are much more difficult to predict. Thus, considering both the inherent difficulties and the trends of reduced error, analysts seem to be doing an adequate job when forecasting loss firm earnings.

Table 8 presents the results for differences in optimism. With respect to the percentage of optimism, it is assumed that the goal when forecasting is to achieve a systematically unbiased 50%. Therefore, the comparison of analyst forecast optimism versus naïve forecast optimism is computed using 50% as a reference. For example, if analysts are optimistic 45% of the time and naïve forecasts are optimistic 65% of the time, then analyst forecasts are superior by 10% with respect to the 50% goal [(65% – 50%) – (50% – 45%) = 10%]. A positive sign indicates better analyst performance; a negative sign indicates better naïve performance.

The results are fascinating. Naïve forecasts for loss firms are primarily optimistic (63.75%) while naïve forecasts for profit firms are primarily pessimistic (35.58%). Thus,

Table 8
Differences between naïve and analyst forecasts: optimism

	Quarterly forecasts					
	Profit			Loss		
	Percent optimistic, analysts	Percent optimistic, naïve	Analyst superiority versus unbiased 50%	Percent optimistic, analysts	Percent optimistic, naïve	Analyst superiority versus unbiased 50%
All years	33.42	35.58	− 2.16	64.43	63.75	− 0.68
1990–1995	40.29	35.63	4.66	76.70	68.10	− 8.60
1996–2001	29.78	35.56	− 5.78	60.69	62.43	1.74
Difference	10.51*	0.07	− 10.44	16.01*	5.67*	10.34
1990	53.13	35.78	11.09	84.07	69.91	− 14.16
1991	51.88	37.62	10.50	78.77	68.49	− 10.28
1992	41.32	35.84	5.48	77.97	65.85	− 12.12
1993	41.90	36.01	5.89	75.00	66.67	− 8.33
1994	37.95	35.23	2.72	74.69	68.19	− 6.50
1995	37.75	35.29	2.46	77.92	70.13	− 7.79
1996	32.50	33.78	− 1.28	72.67	69.16	− 3.51
1997	31.95	33.86	− 1.91	67.54	64.96	− 2.58
1998	30.53	37.15	− 6.62	64.97	65.22	0.25
1999	26.86	35.30	− 8.44	58.83	60.38	1.55
2000	26.18	34.90	− 8.72	52.21	60.58	8.37
2001	29.11	40.99	− 11.88	51.36	55.75	4.39

This table reports the difference between naïve forecast optimism and analyst forecast optimism over the sample period 1990 through 2001. Optimism is present if the mean forecast is greater than the corresponding actual earnings. As 50% is considered the unbiased target, analyst superiority is determined using 50% as the benchmark. Positive numbers in the "analyst superiority versus unbiased 50%" column indicate analyst superiority, while negative numbers indicate naïve forecast superiority. The analyst superiority column is computed as follows:

$$\text{Analyst superiority} = (|\%\ \text{optimistic naïve} - 50\%|) - (|\%\ \text{optimistic analysts} - 50\%|)$$

* Difference is significantly different from zero with 99% confidence.

the optimism analysts show toward loss firms and the pessimism analysts show toward profit firms is perhaps a natural reflection of an easy starting point. For profit firms, in the early sample period, analysts are nearly unbiased. However, as analyst pessimism increases during the sample period for profit firms, analyst superiority with regard to systematic biases steadily changes to inferiority. As an example, analysts are superior relative to the 50% reference for profit firms by 11.09% in 1990 and 10.50% in 1991. However, these numbers decrease to − 8.72% in 2000 and − 11.88% in 2001, indicating a decline in analyst performance. In contrast, for loss firms, analysts move steadily from inferior performance to superior performance. Fig. 2 shows the trends graphically. Like the corresponding table, positive numbers in the figure indicate superior analyst performance.

5. Earnings management, smoothing, and guidance issues

The increase in forecast pessimism (positive surprises) and decrease in forecast error seen in this and other studies is consistent with earnings management, guidance, and

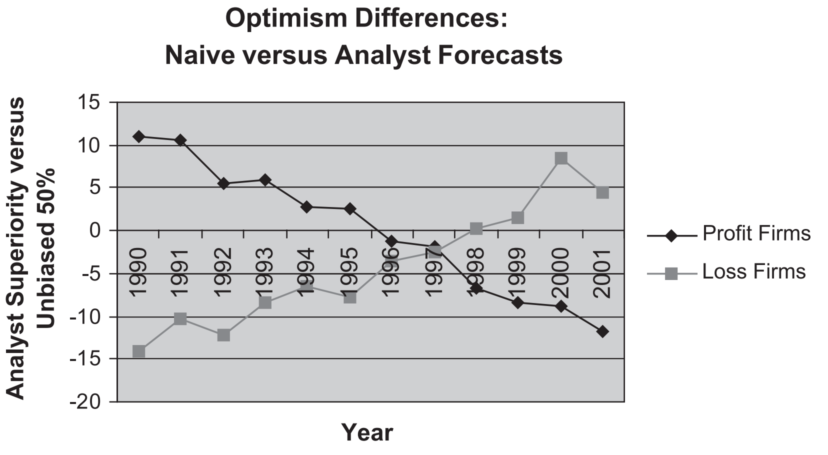

Fig. 2. Analyst versus naïve forecast differences in optimism by year. Note: positive numbers indicate analyst superiority; negative numbers indicate naïve superiority.

smoothing. Various tests are performed to see whether the trends are related to these issues and to differentiate among the potential explanations.

The first procedure examines the subset of firms that failed to meet all three incentives mentioned by Degeorge et al. (1999) when managing earnings: incentives of avoiding losses, avoiding earnings declines, and meeting analyst expectations. Thus, these firms are considered unlikely to be managing earnings as none of the incentives is reached.

Table 9 reports the results. Although the average dispersion, error, and raw error are all higher for this sample of firms versus the full loss firm subsample, similar degrees of improvement in each property are seen. As an example, the average error of these firms drops from 1.23 in the early sample period to 0.93 in the later sample period. This compares with the results for loss firms with either type of surprise from Table 2: 1.02 in the early sample period, decreasing to 0.70 in the later sample period.

To investigate smoothing, trends in earnings volatility are examined. If the decrease in forecasting performance is attributable to increased smoothing, earnings volatility should decrease as well. Earnings volatility is computed as the standard deviation of earnings from the eight most recent quarters. The sample of firms with eight quarters of earnings begins in 1992 and consists of 51,965 firms: 42,543 with profits and 9422 (18.1%) with losses. The trends in earnings volatility are reported in Table 10. Although loss firm earnings volatility decreases, profit firm volatility remains fairly stable across the sample period. Thus, earnings smoothing does not explain trends in profit firm forecasts. For loss firms, the magnitude of the decrease in earnings volatility is far less than the magnitude of the decrease in error and dispersion. Therefore, earnings volatility probably does not explain a large proportion of the trends in loss firm forecasts.

Related testing looks at forecasting trends in a set of firms considered unlikely candidates to smooth earnings, those firms with high earnings volatility. Thus, in each sample year, firms with high earnings volatility are separately analyzed. Both absolute and relative measures of high volatility are used. Absolute measures specify an arbitrary

Table 9
Forecast dispersion, error, and raw error: firms with optimistic forecasts (negative surprises), earnings declines, and losses

	Quarterly forecasts		
	Dispersion	Error	Raw error
All years	0.71	1.01	0.36
1990–1995	1.00	1.23	0.46
1996–2001	0.61	0.93	0.33
Difference	0.39*	0.30*	0.13*
1990	0.87	1.28	0.52
1991	1.20	1.27	0.65
1992	1.12	1.19	0.46
1993	1.03	1.14	0.52
1994	0.94	1.21	0.44
1995	0.93	1.31	0.39
1996	0.87	1.08	0.38
1997	0.66	0.99	0.34
1998	0.63	0.95	0.29
1999	0.54	0.94	0.33
2000	0.47	0.85	0.35
2001	0.50	0.74	0.25

This table reports mean analyst quarterly forecast properties for firms with optimistic forecasts, earnings declines, and losses over the sample period 1990 through 2001. An earnings decline is when actual quarterly earnings are less than the previous quarter's actual earnings. See Table 1 for the other variable definitions.

* Difference is significantly different from zero with 99% confidence.

earnings volatility number to which each firm's earnings volatility is compared, thus controlling for any changes in average volatility during the sample period. Quarterly earnings volatility is considered high if the standard deviation of the actual Street earnings is greater than US$0.50 per share over the prior eight quarters.[9] Under the relative measures of volatility, a firm is considered to have high earnings volatility if its volatility is in the top 10% during the year. Although the results are not tabulated, the same trends of decreasing dispersion, error, and optimism throughout the sample period still exist for the high earnings volatility sample of firms using either the absolute or relative volatility measures.

The next test investigates earnings guidance by isolating firms with high dispersion. These firms are often considered to have a greater disparity of opinion (e.g., Krishnaswami & Subramaniam, 1999) and are, therefore, unlikely to be guiding analysts toward a specific earnings target.

Similar to the volatility tests, absolute and relative measures are used. Under the absolute method, firms are considered to have high dispersion if their dispersion measure is greater than or equal to 0.50.[10] This sample contains 8225 firms (9.7% of the full dispersion sample), 4028 with profits and 4197 (51.0%) with losses. Under the relative measure, firms are considered to have high dispersion if their dispersion measure is in the top 10% during the relevant year.

[9] Other arbitrary cutoff points are employed with similar results.
[10] Other arbitrary cutoff points are employed with similar results.

Table 10
Earnings volatility by year

	Eight quarter earnings volatility		
	All	Profit	Loss
All years	0.17	0.14	0.28
1992–1996	0.17	0.14	0.36
1997–2001	0.16	0.14	0.25
Difference	0.01*	0.00	0.11*
1992	0.18	0.16	0.32
1993	0.18	0.15	0.35
1994	0.18	0.16	0.35
1995	0.18	0.14	0.43
1996	0.16	0.13	0.33
1997	0.16	0.14	0.29
1998	0.15	0.13	0.23
1999	0.16	0.14	0.24
2000	0.16	0.14	0.26
2001	0.18	0.15	0.26

This table reports mean quarterly earnings volatility over the sample period 1992 through 2001. Quarterly earnings volatility is defined as the standard deviation of actual earnings from the eight previous quarters. As 2 years of earnings are needed before the volatility can be computed, the sample period does not include 1990 and 1991.

* Difference is significantly different from zero with 99% confidence.

Table 11
Forecast error, raw error, and optimism by profitability: firms with dispersion greater than 0.50

	Quarterly forecasts								
	Error			Raw error			Percent optimistic		
	All	Profit	Loss	All	Profit	Loss	All	Profit	Loss
All years	1.09	1.14	1.04	0.23	0.13	0.33	64.61	39.95	88.28
1990–1995	1.21	1.24	1.17	0.30	0.19	0.42	69.24	49.36	90.93
1996–2001	1.01	1.07	0.96	0.19	0.08	0.28	61.76	33.51	86.81
Difference	0.20*	0.17*	0.21*	0.11*	0.11*	0.14*	7.48*	15.85*	4.12*
1990	1.35	1.60	1.09	0.55	0.37	0.74	73.85	58.82	90.32
1991	1.15	1.18	1.13	0.38	0.17	0.60	68.05	48.77	88.74
1992	1.11	1.13	1.09	0.32	0.21	0.45	66.73	47.71	90.00
1993	1.20	1.27	1.12	0.26	0.19	0.34	69.06	49.37	91.43
1994	1.23	1.21	1.25	0.30	0.21	0.40	67.97	48.56	90.12
1995	1.26	1.30	1.22	0.24	0.12	0.35	71.90	50.00	92.65
1996	1.12	1.13	1.11	0.24	0.11	0.38	66.83	41.83	91.40
1997	1.01	1.06	0.97	0.20	0.08	0.31	63.19	36.77	87.94
1998	0.97	1.03	0.93	0.17	0.07	0.26	64.15	35.50	86.82
1999	0.98	1.08	0.90	0.18	0.08	0.27	56.75	25.67	85.02
2000	1.02	1.09	0.96	0.16	0.08	0.22	56.10	29.21	80.94
2001	0.90	0.95	0.87	0.16	0.08	0.22	60.13	25.95	86.47

This table reports mean analyst quarterly forecast properties for firms with forecast dispersion greater than 0.50 over the sample period 1990 through 2001. See Table 1 for variable definitions.

* Difference is significantly different from zero with 99% confidence.

Table 11 presents the results using the absolute measure. (The results using the relative measure are similar.) There is a clear reduction in forecast error and raw error during the sample period for both profit and loss firms. Optimism also decreases dramatically for profit firms, starting around 50% in the first few sample years, but reaching below 30% for the last three sample years. Loss firms, however, are dominated by overwhelming optimism throughout the sample period (an average of 88.28%), the lack of improvement indicating a problem area that analysts should address. Thus, although analysts have reduced the size of their errors for firms with high dispersion, they still tend to overestimate the earnings of high dispersion, loss firms. This testing suggests that systematic profit firm pessimism occurs regardless of whether the forecasts are guided. However, the reduction of loss firm optimism occurs when firms warn analysts of the impending loss.

Overall, the improved forecasting ability of analysts occurs regardless of increases in earnings management, guidance, or smoothing. The trends are consistent with concerns of legal liability as most of the reduction in dispersion and error is due to loss firms. The trends are also consistent with improved analyst forecasting abilities. The increase in pessimism for profit firms may be partly attributed to an overreliance on the previous period's earnings.

6. GAAP versus Street earnings and Regulation FD

Another issue is related to the Street versus GAAP earnings debate. Abarbanell and Lehavy (2000) suggest that using forecast provider databases, such as First Call, to obtain earnings data might impact conclusions reached in earnings-related studies. First Call collects data based on the earnings that firms publicize to the market, often known as Street earnings, which may be different from GAAP earnings. Therefore, following the procedure of Brown (2001), the sample of firms in which GAAP earnings from Compustat equal Street earnings from First Call are examined separately. The earnings are considered equal if the absolute value of the difference is less than US$0.02 to control for rounding differences and materiality. The results (not shown) are similar to the previous results for the reduced sample. Moreover, the difference in Street versus GAAP earnings has not increased over the sample period (not shown).

Finally, the passage of Regulation FD in August 2000 and its subsequent implementation on October 23, 2000 might affect forecasts made during the surrounding time periods. To investigate this issue, the quarterly forecast properties from the beginning of 1999 through the end of 2001 are computed for only firms that have fiscal quarters on a March, June, September, December cycle. This provides a sample with three distinct, easily identifiable subperiods: (1) a pre-Regulation FD period, from the first quarter of 1999 through the second quarter of 2000; (2) a period during the implementation of Regulation FD, the third and fourth quarters of 2000; and (3) a post-Regulation FD period, the first quarter of 2001 through the fourth quarter of 2001. The second period, during the implementation, includes the quarter in which the regulation was passed.

Table 12
Forecast dispersion, error, raw error, and optimism surrounding implementation of regulation FD

Year: month	Profit firms				Loss firms			
	Dispersion	Error	Raw error	Percent optimistic	Dispersion	Error	Raw error	Percent optimistic
Pre								
1999: 3	0.15	0.35	0.05	27.35	0.39	0.66	0.15	56.36
1999: 6	0.13	0.33	0.05	26.49	0.40	0.67	0.16	57.89
1999: 9	0.14	0.34	0.05	27.96	0.41	0.66	0.19	56.41
1999: 12	0.15	0.34	0.06	25.42	0.37	0.74	0.28	59.95
2000: 3	0.13	0.35	0.05	23.89	0.34	0.59	0.17	50.55
2000: 6	0.13	0.32	0.05	24.49	0.28	0.64	0.19	49.63
During								
2000: 9	0.13	0.31	0.06	28.71	0.23	0.60	0.19	47.68
2000: 12	0.14	0.32	0.06	29.63	0.30	0.64	0.26	56.54
Post								
2001: 3	0.14	0.33	0.05	30.90	0.33	0.51	0.17	52.74
2001: 6	0.16	0.35	0.05	27.40	0.30	0.53	0.14	51.75
2001: 9	0.16	0.37	0.06	34.47	0.34	0.56	0.18	54.89
2001: 12	0.15	0.33	0.05	22.41	0.32	0.54	0.13	47.02

This table reports mean analyst quarterly forecast properties for the quarters surrounding the implementation of Regulation Free Disclosure (Reg FD). Reg FD was passed in August 2000 and implemented in October 2000. See Table 1 for variable definitions. Only firms with fiscal quarters ending in March, June September, and December are included in the sample.

After evaluating the results, presented in Table 12 for profit and loss subsamples, there are no identifiable differences in the forecast property trends during the three periods surrounding Regulation FD implementation regardless of whether the sample includes all firms, profit firms, or loss firms.

7. Conclusions

This study documents almost continuous reductions in analyst forecast dispersion, error, and optimism during the time period 1990 through 2001. The reductions, however, primarily come about due to staggering advances in forecasting loss firm earnings. At the end of the sample period, differences in forecasting performance between profit and loss firms are relatively small. Attempts are made to control for various issues that might affect the conclusions, such as earnings management, guidance, and smoothing, Street versus GAAP earnings, or Regulation FD. None of those issues can wholly explain the trends.

In addition, it appears that loss firm earnings are more difficult to predict. Given the prediction difficulties, the value provided to the market by analysts appears to be greater for loss firms versus profit firms.

While this study does not contradict prior studies showing increases in earnings management or guidance, it does shed additional light on the issue. Analysts are undoubtedly not as optimistic, their incentives to get investment banking clients or private information perhaps no longer as important as the notoriety they receive when they mislead investors.

Future studies can examine trends in analyst buy, sell, or hold recommendations, another area in which the media and academic research (and also the Securities and Exchange Commission) have criticized analysts. Analysts are known to frequently make buy recommendations but rarely make sell recommendations, often preferring to drop coverage of a firm rather than issue a sell recommendation (e.g., Barber, Lehavy, McNichols, & Trueman, 2001; McNichols & O'Brien, 1997; Stickel, 1995).

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Biased forecasts or biased earnings? The role of reported earnings in explaining apparent bias and over/underreaction in analysts' earnings forecasts ☆

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Abstract

The extensive literature that investigates whether analysts' earnings forecasts are biased and/or inefficient has produced conflicting evidence and no definitive answers to either question. This paper shows how two relatively small but statistically influential asymmetries in the tail and the middle of distributions of analysts' forecast errors can exaggerate or obscure evidence consistent with analyst bias and inefficiency, leading to inconsistent inferences. We identify an empirical link between firms' recognition of unexpected accruals and the presence of the two asymmetries in distributions of forecast errors that suggests that firm reporting choices play an important role in determining analysts' forecast errors.

JEL classification: G10; G14; M41

Keywords: Analysts' forecasts; Earnings management; Bias; Inefficiency

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1. Introduction

Four decades of research have produced an array of empirical evidence and a set of behavioral and incentive-based theories that address two fundamental questions: Are analysts' forecasts biased? And Do analysts underreact or overreact to information in prior realizations of economic variables? This empirical literature has long offered conflicting conclusions and is not converging to a definitive answer to either question. On the one hand, theories that predict optimism in forecasts are consistent with the persistent statistical finding in the literature of cross-sectional negative (i.e., bad news) mean forecast errors as well as negative intercepts from regressions of forecasts on reported earnings. On the other hand, such theories are inconsistent both with the finding that median forecast errors are most often zero and with the fact that the percentage of apparently pessimistic errors is greater than the percentage of apparently optimistic errors in the cross-section. A similar inconsistency is found in the literature on analyst over/underreaction to prior realizations of economic variables, including prior stock returns, prior earnings changes, and prior analyst forecast errors. Here, again, empirical evidence supports conflicting conclusions that analysts overreact to prior news, underreact to prior news, and both underreact and overreact as a function of the sign of prior economic news. Further reflecting the lack of consensus in the literature, a handful of studies fail to reject unbiasedness and efficiency in analyst forecasts after "correcting" methodological flaws or assuming nonstandard analyst loss functions.[1]

The accumulation of often inconsistent results concerning analyst rationality and incentives makes it difficult for researchers, practitioners, and policy makers to understand what this literature tells us. This motivates us to reexamine the body of evidence with the goal of identifying the extent to which particular theories for apparent errors in analysts' forecasts are supported by the data. Such an exercise is both appropriate and necessary at this juncture as it can, among other things, lead to modified theories that will be tested using the new and unique hypotheses they generate.

We extend our analysis beyond a synthesis and summary of the findings in the literature by identifying the role of two relatively small asymmetries in the cross-sectional distributions of analysts' forecast errors in generating conflicting statistical evidence. We note that the majority of conclusions concerning analyst-forecast rationality in the literature are directly or indirectly drawn from analyses of these distributions. The first asymmetry is a larger number and a greater magnitude of observations that fall in the extreme negative relative to the extreme positive tail of the forecast error distributions (hereafter, the *tail asymmetry*). The second asymmetry is a higher incidence of small positive relative to small negative forecast errors in cross-sectional distributions (hereafter, *the middle asymmetry*). The individual and combined impact of these asymmetries on statistical tests leads to three important observations. First, differences in the manner in which researchers

[1] A representative selection of evidence and theory relevant to both the bias and over/underreaction literatures is discussed in the body of the paper.

implicitly or explicitly weight observations that fall into these asymmetries contribute to inconsistent conclusions concerning analyst bias and inefficiency. Second, a variety of econometric techniques and data adjustments fail to eliminate inconsistencies in inferences across different statistical indicators and conditioning variables. Such techniques include using indicator variables or data partitions in parametric tests, applying nonparametric methods, and performing data truncations and transformations. Third, econometric approaches that choose loss functions that yield consistent inferences—essentially by attenuating the statistical impact of observations that comprise the asymmetries—will not provide definitive answers to the question of whether analysts' forecasts are biased and inefficient. This is because at this stage in the literature too little is known about analysts' actual loss functions, and such methods thus leave unresolved the question of why the asymmetries in forecast error distributions are present.

We present statistical evidence that demonstrates how the two asymmetries in forecast error distributions can indicate analyst optimism, pessimism, or unbiasedness. We also show how observations that comprise the asymmetries can contribute to, as well as obscure, a finding of apparent analyst inefficiency with respect to prior news variables, including prior returns, prior earnings changes, and prior forecast errors. For example, our empirical evidence explains why prior research that relies on parametric statistics always finds evidence of optimistic bias as well as apparent analyst underreaction to prior bad news for all alternative variables chosen to represent prior news. It also explains why evidence of apparent misreaction to good news is *not* robust across parametric statistics or across prior news variables, and why the degree of misreaction to prior bad news is always greater than the degree of misreaction to prior good news, regardless of the statistical approach adopted or the prior information variable examined.

Finally, while our analysis does not lead to an immediately obvious solution to problems of inferences in the literature, it does reveal a link between the reported earnings typically employed to benchmark forecasts and the presence of the two asymmetries in distributions of forecast errors. Specifically, we find that extreme negative unexpected accruals included in reported earnings go hand in hand with observations in the cross-section that generate the tail asymmetry. We also find that the middle asymmetry in distributions of forecast error is eliminated when the reported earnings component of the earnings surprise is stripped of unexpected accruals. This evidence suggests benefits to refining extant cognitive- and incentive-based theories of analyst forecast bias and inefficiency so that they can account for an endogenous relation between forecast errors and manipulation of earnings reports by firms. The evidence also highlights the importance of future research into the question of whether reported earnings are, in fact, the correct benchmark for assessing analyst bias and inefficiency. This is because common motivations for manipulating earnings can give rise to the appearance of analyst forecast errors of exactly the type that comprise the two asymmetries if unbiased and efficient forecasts are benchmarked against manipulated earnings. Thus, it is possible that some evidence previously deemed to reflect the impact of analysts' incentives and cognitive tendencies on forecasts is, after all, attributable to the fact that analysts do not have the motivation or ability to completely anticipate earnings management by firms in their forecasts.

This paper's emphasis is on fleshing out salient characteristics of forecast error distributions with an eye toward ultimately explaining how they arise. The analysis highlights the importance of new research that explains the actual properties of forecast error data and cautions against the application of econometric fixes that either fit the data to specific empirical models or fit specific empirical models to the data without strong a priori grounds for doing so. Our findings also represent a step toward understanding what analysts really aim for when they forecast, which is useful for developing more appropriate null hypotheses in tests of analysts' forecast rationality, and sounder statistical test specifications, as well as the identification of first-order effects that may require control when testing hypotheses that predict analyst forecast errors.

In the next section we describe our data and present evidence of the sensitivity of statistical inferences concerning analyst optimism and pessimism to relatively small numbers of observations that comprise the tail and middle asymmetries. Section 3 extends the analysis to demonstrate the impact of the two forecast error asymmetries on inferences concerning analyst over/underreaction conditional on prior realizations of stock returns and earnings changes, as well as on serial correlation in consecutive-quarter forecast errors. Section 4 presents evidence of a link between biases in reported earnings and the two asymmetries and discusses possible explanations for this link as well as the implications for interpreting evidence from the literature and for the conduct of future research. A summary and conclusions are provided in Section 5.

2. Properties of typical distributions of analysts' forecast errors and inferences concerning analysts' optimism, pessimism, and unbiasedness

2.1. Data

The empirical evidence in this paper is drawn from a large database of consensus quarterly earnings forecasts provided by Zacks Investment Research. The Zacks earnings forecast database contains approximately 180,000 consensus quarterly forecasts for the period 1985–1998. For each firm quarter we calculate forecast errors as the actual earnings per share (as reported in Zacks) minus the consensus earnings forecast outstanding prior to announcement of quarterly earnings, scaled by the stock price at the beginning of the quarter and multiplied by 100. Our results are insensitive to alternative definitions of forecasts such as the last available forecast or average of the last three forecasts issued prior to quarter-end. Inspection of the data revealed a handful of observations that upon further review indicated data errors. These observations had no impact on the basic features of cross-sectional distributions of errors that we describe, but they were nevertheless removed before carrying out the statistical tests reported in this paper. Empirical results obtained after removing these observations were virtually identical to those obtained when the distributions of quarterly forecast errors were winsorized at the 1st and 99th percentiles, a common practice for mitigating the possible effects of data errors followed in the literature. (To enhance comparability with the majority of studies cited below, all test results reported in the paper are based on the winsorized data.)

Lack of available price data reduced the sample size to 123,822 quarterly forecast errors. The data requirements for estimating quarterly accruals further reduced the sample on which our tabled results are based to 33,548 observations.[2] For the sake of brevity we present only results for this reduced sample. We stress, however, that the middle and tail symmetries we document below are present in the full sample of forecast errors and that the proportion of observations that comprise these asymmetries is roughly the same as that for the reduced sample. Moreover, the descriptive evidence and statistical findings relevant to apparent bias and inefficiency in analyst forecasts presented in this section and the next are qualitatively similar when we do not impose the requirement that data be available to calculate unexpected accruals.[3]

2.2. The impact of asymmetries in the distribution of forecast errors on inferences concerning bias

One of the most widely held beliefs among accounting and finance academics is that incentives and/or cognitive biases induce analysts to produce generally optimistic forecasts (see, e.g., reviews by Brown (1993) and Kothari, 2001). This view is repeatedly reinforced when studies that employ analysts' forecasts as a measure of expected earnings present descriptive statistics and refer casually to negative mean forecast errors as evidence of the purportedly ‘‘well-documented’’ phenomenon of optimism in analyst forecasts.[4] The belief is even more common among regulators (see, e.g., Becker, 2001) and the business press (see, e.g., Taylor, 2002). In spite of the prevalent view of analyst forecast optimism, summary statistics associated with forecast error distributions reported in Panel A of Table 1 raise doubts about this conclusion.

[2] As described in Section 4, we use a quarterly version of the modified Jones model to estimate accruals. For the purposes of sensitivity tests, we also examine a measure of unexpected accruals that excludes nonrecurring and special items (see, Hribar and Collins, 2002), and use this adjusted measure in conjunction with *Zacks*' consensus forecast estimates and actual reported earnings, which also exclude such items. All the results involving unexpected accruals reported in the paper are qualitatively unaltered using this alternative measure.

[3] The results are also qualitatively similar when data from alternative forecast providers (I/B/E/S and First Call) are employed, indicating that the findings we revisit in this study are not idiosyncratic to a particular data source (see, Abarbanell and Lehavy, 2002).

[4] The perception is also strengthened in a number of studies that place analyst forecasts and reported earnings numbers (i.e., the two elements that comprise the forecast error) on opposite sides of a regression equation. These studies uniformly find significant intercepts and either casually refer to them as consistent with analyst optimism or emphasize them in supporting their prediction of analyst bias. Evidence presented below, however, indicates a nonlinear relation between forecasts and earnings, which contributes to nonzero intercepts in OLS regressions.

Table 1
Descriptive statistics on quarterly distributions of forecast errors (Panel A), the tail asymmetry (Panel B), and the middle asymmetry (Panel C), 1985–1998

Panel A: Statistics on forecast error distributions

Number of observations	33,548
Mean	−0.126
Median	0.000
% Positive	48%
% Negative	40%
% Zero	12%

Panel B: Statistics on the "tail asymmetry" in forecast error distributions

P5	−1.333
P10	−0.653
P25	−0.149
P75	0.137
P90	0.393
P95	0.684

Panel C: Statistics on the "middle asymmetry" in forecast error distributions

Range of forecast errors (1)	Ratio of positive to negative forecast errors (2)	% of total number of observations (3)
Overall	1.19	100
Forecast errors = 0		12
[−0.1, 0) & (0, 0.1]	1.63*	29
[−0.2, −0.1) & (0.1, 0.2]	1.54*	18
[−0.3, −0.2) & (0.2, 0.3]	1.31*	10
[−0.4, −0.3) & (0.3, 0.4]	1.22*	7
[−0.5, −0.4) & (0.4, 0.5]	1.00	5
[−1, −0.5) & (0.5, 1]	0.83*	11
[Min, −1) & (1, Max]	0.40*	9

This table provides descriptive statistics on quarterly distributions of forecast errors for the period of 1985–1998. Analyst earnings forecasts and actual realized earnings are provided by *Zacks Investment Research*. Panel A provides the mean, median, and frequencies of quarterly forecast errors. Panel B provides percentile values of forecast error distributions. Panel C reports the ratio of positive to negative forecast errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors. For example, the forecast error range of [−0.1, 0) & (0, 0.1] includes all observations that are greater than or equal to −0.1 and (strictly) less than zero and observations that are greater than zero and less than or equal to 0.1. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price.

* A test of the difference in the frequency of positive to negative forecast errors is statistically significant at or below a 1% level.

As can be seen in Panel A, the only statistical indication that supports the argument for analyst optimism is a fairly large negative mean forecast error of −0.126. In contrast, the median error is zero, suggesting unbiased forecasts, while the percentage of positive errors is significantly greater than the percentage of negative errors (48% vs. 40%), suggesting apparent analyst pessimism.

To better understand the causes of this inconsistency in the evidence of analyst biases among the summary statistics, we take a closer look at the distribution of forecast errors. Panel A of Fig. 1 presents a plot of the 1st through the 100th percentiles of the pooled quarterly distributions of forecast errors over the sample period. Moving from left to right, forecast errors range from the most negative to the most positive.

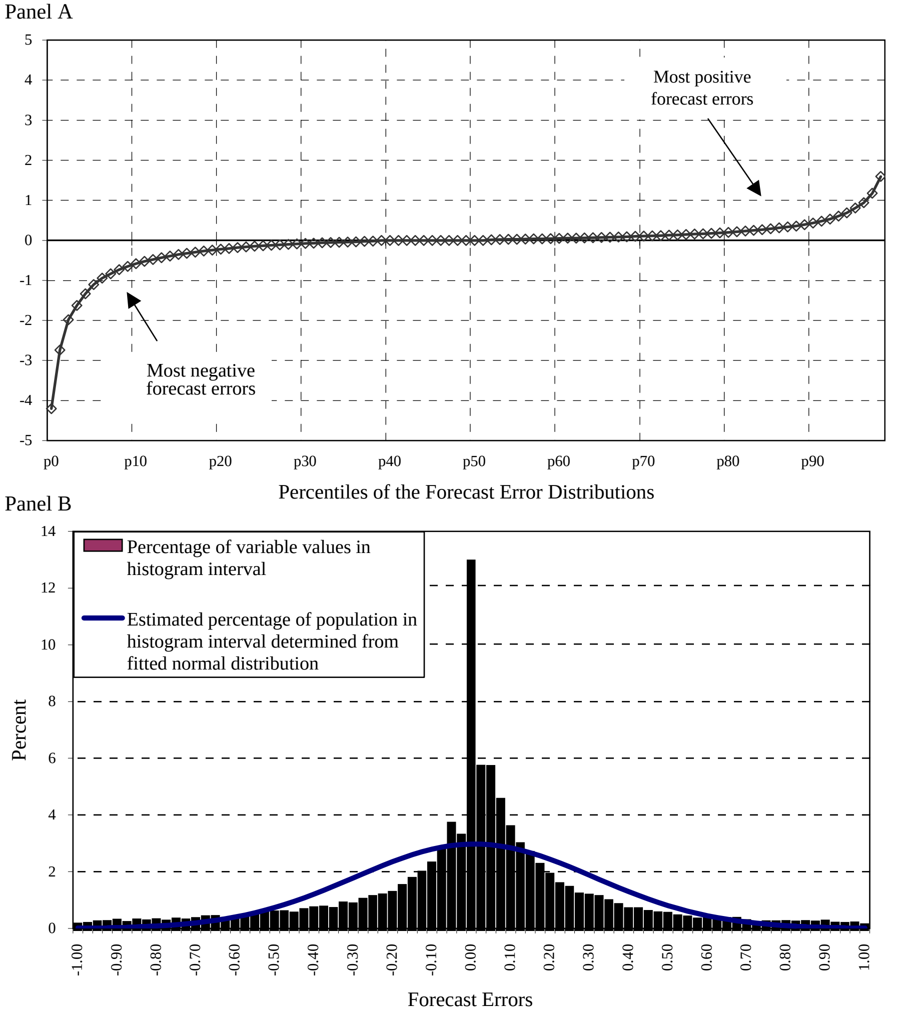


Fig. 1. Percentile values of quarterly distributions of analyst forecast errors (Panel A) and histogram of forecast errors for observations within forecast errors of -1 to $+1$ (Panel B). Panel A depicts percentile values of quarterly distributions of analyst forecast errors. Panel B presents percentage of forecast error values in histogram intervals for observations within a forecast error of -1% to $+1\%$ of the beginning-of-period stock price. Forecast error equals reported earnings minus the consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price ($N = 33{,}548$).

One distinctive feature of the distribution is that the left tail (ex-post bad news) is longer and fatter than the right tail, i.e., far more extreme forecast errors of greater absolute magnitude are observed in the ex-post "optimistic" tail of the distribution than in the "pessimistic" tail. We refer to this characteristic of the distribution as the *tail asymmetry*. Although Fig. 1 summarizes the distribution of observations over the entire sample period, unreported results indicate that a tail asymmetry is present in each quarter represented in the sample. To get a sense of the magnitude of the asymmetry, we return to Panel B of Table 1, where the 5th percentile (extreme negative forecast errors) is nearly twice the size observed for the 95th percentile (−1.333 vs. 0.684). Alternatively, we find that 13% of the observations fall below a negative forecast error of −0.5, while only 7% fall above a positive error of an equal magnitude (not reported in the table).

Closer visual inspection of the data reveals a second feature of the distribution depicted in Panel B of Fig. 1—a higher frequency of small positive forecast errors versus small negative errors. Specifically, the figure presents the frequencies of forecast errors that fall in fixed subintervals of 0.025 within the range of −1 to +1. Clearly, the *incidence* of small positive relative to small negative errors increases as forecast errors become smaller in absolute magnitude. We refer to this property of the distribution as the *middle asymmetry*.[5] Statistics on the magnitude of the middle asymmetry are reported in Panel C of Table 1. This panel presents the ratio of positive (i.e., apparently pessimistic) errors to negative errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors. Consistent with the visual evidence in Panel B of Fig. 1, this ratio increases for smaller, symmetric intervals of forecast errors, reaching 1.63 in the smallest interval examined (significantly different from 1, as well as significantly different from the ratios calculated for the larger intervals).[6] Another distinguishing feature of the distribution seen in Panel C of Table 1 and evident in both Panels A and B of Fig. 1 is the large number of exactly zero observations (12%). Depending on one's previous exposure to the data or instincts about the task of forecasting, the magnitude of the clustering at exactly zero may not seem

[5] The visual evidence in Panel B of Fig. 1 is consistent with specific circumstances in which analysts have incentives to produce forecasts that fall slightly short of reported earnings (see, e.g., Degeorge et al., 1999; Matsumoto, 2002; Brown, 2001; Burgstahler and Eames, 2002; Bartov et al., 2000; Dechow et al., 2003; Abarbanell and Lehavy, 2003a, b). However, prior studies have not considered the impact of observations that comprise the middle asymmetry on inferences concerning the *general* tendency of analysts to produce biased and/or inefficient forecasts.

[6] An analysis of unscaled forecast errors confirms that rounding down a greater number of negative than positive forecast errors to a value of zero when errors are scaled by price does not systematically induce the middle asymmetry (see, Degeorge et al., 1999). Similarly, there is no obvious link between the presence of the middle asymmetry and round-off errors induced by the application of stock-split factors to consensus forecast errors discussed in Baber and Kang (2002) and Payne and Thomas (2002). Abarbanell and Lehavy (2002) present evidence confirming the presence of the middle asymmetry in samples confined to firms with stock-split factors of less than 1.

surprising. Nevertheless, the large number of forecasts of exactly zero has important impacts on statistical inferences.[7]

The statistics presented above indicate that the tail asymmetry pulls the mean forecast error toward a negative value, supporting the case for analyst optimism. But, as shown in Panel C of Table 1, the excess of *small* positive over *small* negative errors associated with the middle asymmetry is largely responsible for a significantly higher overall incidence of positive to negative forecast errors in the distribution, thus supporting the case for analyst pessimism. Finally, a zero median forecast error, which supports an inference of analyst unbiasedness, reflects the countervailing effects of the middle asymmetry and tail asymmetries. A rough calculation pertaining to the nonzero forecast errors in the interval between [−0.1, 0) and (0, 0.1] gives a sense of these effects. There are 9662 observations in this region. If nonzero forecast errors were random, we would expect 4831 forecasts to be positive, when in fact 5928 are positive, indicating that small errors in the distribution of absolute magnitude less than or equal to 0.1 contribute 1097 more observations to the right of zero than would be expected if the distribution was symmetric. This region of the forecast error distribution contains 29% of all observations but contributes more than 42% of the total number of pessimistic errors in excess of optimistic errors and represents roughly 3.3% of the entire distribution. Their impact offsets, all else being equal, the contribution of approximately 2.5% of negative observations in excess of what would be expected if the distribution of errors were symmetric, arising from the tail asymmetry (relative to the extreme decile cutoffs of a fitted normal distribution). Because 12% of the forecast error sample has a value of exactly zero, the relative sizes of the tail and middle asymmetries are each sufficiently small (and offsetting) to ensure that the median error remains at zero.

The evidence in Table 1 and Fig. 1 yields two important implications for drawing inferences about the nature and extent of analyst bias. First, depending on which summary statistic the researcher chooses to emphasize, support can found for analyst optimism, pessimism, and even unbiasedness. Second, if a researcher relies on a given summary statistic to draw an inference about analyst bias, a relatively small percentage of observations in the distribution of forecast errors will be responsible for his or her conclusion. This is troublesome because extant hypotheses that predict analyst optimism or pessimism typically do not indicate how often the phenomenon will occur in the cross-section and often convey the impression that

[7] Because many factors can affect the process that generates the typical distribution of forecast errors, there is no reason to expect them to be normally or even symmetrically distributed. Supplemental analyses unreported in the tables reject normality on the basis of skewness and kurtosis. It is interesting to note, however, that kurtosis in the forecast error distribution does not align with the typical descriptions of leptokurtosis (high peak and fat tails) or platykurtosis (flat center and/or shoulders). Relative to decile cutoffs of the fitted normal distribution, we find that the most extreme negative decile of the actual distribution contains only 5% of the observations and the most extreme positive decile contains only 2.5% of the observations. Thus, even though the extreme negative tail is roughly twice the size of the extreme pessimistic tail, extreme observations are actually *underrepresented* in the distribution relative to a normal, especially in the positive tail. The thinner tails and shoulders of the distribution highlight the role of peakedness as a source of deviation from normality, a fact that is relevant to assessing the appropriateness of statistics used by researchers to draw inferences about analyst forecast bias.

bias will be pervasive in the distribution (see, studies suggesting that analysts are hard-wired or motivated to produce optimistic forecasts, e.g., Affleck-Graves et al. (1990), Francis and Philbrick (1993), and Kim and Lustgarten (1998), or that selection biases lead to hubris in analysts' earnings forecasts, e.g., McNichols and O'Brien, 1997).[8]

Some studies have explicitly recognized the disproportional impact of extreme negative forecast errors on conclusions drawn in the literature, but for the most part they have had little influence on general perceptions. For example, Degeorge et al. (1999) predict a tendency for pessimistic errors to occur but recognize the common perception that analyst forecasts are optimistic; they note in passing that extreme negative forecast errors are responsible for an optimistic mean forecast in their sample. Some studies also tend to deal with this feature of the data in an ad hoc manner. Keane and Runkle (1998), for example, recognize the impact of extreme negative forecast errors on statistical inferences concerning analyst forecast rationality and thus eliminate observations from their sample based on whether reported earnings contain large negative special items. However, Abarbanell and Lehavy (2002) show that there is a very high correlation between observations found in the extreme negative tail of forecast error distributions and firms that report large negative special items, even when special items are excluded from the reported earnings benchmark used to calculate the forecast error. Thus, by imposing rules that eliminate observations from their sample based on the size of negative special items, Keane and Runkle (1998) effectively truncate the extreme negative tail of forecast error distributions, and in so doing nearly eliminate evidence of mean optimism in their sample.

Some researchers are less explicit in justifying the removal of observations from the distribution of forecast errors when testing for forecast rationality, or are unaware that they have done so in a manner that results in sample distributions that deviate substantially from the population distribution. For example, many studies implicitly limit observations in their samples to those that are less extreme by choosing ostensibly symmetric rules for eliminating them, such as winsorization or truncations of values greater than a given absolute magnitude.[9] It should be evident from Panel A of Fig. 1 that such rules inherently mitigate the statistical impact of the

[8] A notable exception is the attribution of optimism in analysts' earnings forecasts to incentives to attract and maintain investment banking relationships (see, e.g., Lin and McNichols, 1998; Dugar and Nathan, 1995). Evidence consistent with this argument is based on fairly small samples of firms issuing equity. We emphasize that all the qualitative results in this paper are unaltered after eliminating observations for which an IPO or a seasoned equity offering took place within 1 year of the date of a forecast. Furthermore, the number of observations removed from the sample for this reason represents a very small percentage of those in each of the quarters in our sample period.

[9] For example, Kothari (2001) reports that Lim (2001) excludes absolute forecast errors of $10 per share or more, Degeorge et al. (1999) delete absolute forecast errors greater than 25 cents per share, Richardson et al. (1999) delete price-deflated forecast errors that exceed 10% in absolute value, and Brown (2001) winsorizes absolute forecast errors greater than 25 cents per share (which implies a much larger tail winsorization than typically undertaken to remove possible data errors). While none of these procedures, when applied to our data, completely eliminates the tail asymmetry, all of them substantially attenuate to varying degrees its statistical impact on our tests.

tail asymmetry and arbitrarily transform the distribution, frequently without a theoretical or institutional reason for doing so.[10]

One might justify truncating data on the grounds that the disproportional impact of the extreme tail makes it difficult detect general tendencies, or that such "errors" may not accurately reflect factors relevant to analysts' objective functions (see, e.g., Abarbanell and Lehavy, 2003b; Gu and Wu, 2003; Keane and Runkle, 1998). However, it is possible for researchers to "throw the baby out with the bathwater" if they assume that these observations do not reflect the effects of incentives or cognitive biases, albeit in a more noisy fashion than other observations in the distribution. Another concern that arises from transforming the distribution of errors without justification is that it may suppress one feature of the data (e.g., the tail asymmetry), leaving another unusual but more subtle feature of the distribution (e.g., the middle asymmetry) to dominate an inference that forecasts are generally biased or to offset the other and yield an inference that forecasts are generally unbiased. This is an important issue because there has been a tendency in the literature on forecast rationality for new hypotheses to crop up motivated solely by the goal of explaining "new" empirical results. For example, after truncating large absolute values of forecast errors, Brown (2001) finds that the mean and median forecasts in recent years indicate a shift away from analyst optimism and toward analyst pessimism. Increasing pessimism as a function of market sentiment as reflected in changes in price level or changes in analyst incentives has also been a subject of growing interest in the behavioral finance literature. Clearly, when data inclusion rules that systematically reduce the tail asymmetry are applied, empirical evidence in support of increasing or time-varying analyst pessimism will be affected by the size and magnitude of the remaining middle asymmetry.

Perhaps the most unsatisfying aspect of the evidence presented in Table 1 is the fact that general incentive and behavioral theories of analyst forecast errors are not sufficiently developed at this stage to predict that when forecast errors are extreme they are more likely to be *optimistic* and when forecast errors are small they are more likely to be *pessimistic*. That is, individual behavioral and incentive theories for analyst forecast errors do not account for the simultaneous presence of the two asymmetries that play such an important role in generating evidence consistent with analyst bias and, as we show in the next section, analyst forecast inefficiency with respect to prior information (see Abarbanell and Lehavy, 2003a, for an exception).

3. The effect of the two asymmetries on evidence of apparent analyst misreaction to prior stock returns, prior earnings changes, and prior forecast errors

In this section, we demonstrate how observations that comprise the tail and middle asymmetries in forecast error distributions *conditional on prior realizations of*

[10] For example, in our data an arbitrary symmetric truncation of the distribution at the 10th and the 90th percentiles reduces the measure of skewness in the remainder of the distribution to a level that does not reject normality and results in a mean forecast error near zero among the remaining observations. A similar effect occurs with an arbitrary one-sided truncation of the negative tail at a value as low as the 3rd percentile.

economic variables contribute to inconsistent inferences concerning the efficiency of analysts' forecasts. One important message of the ensuing analysis is that the likelihood that a forecast error observation falls into one or the other asymmetry varies by the sign and magnitude of the prior news. This feature of the data links the empirical literature on analyst inefficiency to the heretofore separate literature on analyst bias. This is because observations that comprise the two asymmetries and lead—depending on the statistic relied on—to inconsistent inferences concerning analyst bias also contribute to conflicting inferences concerning whether analysts underreact, overreact, or react efficiently to prior news.

We consider realizations of three economic variables: prior period stock returns, prior period earnings changes, and prior period analyst forecast errors. These three variables are those most often identified in previous studies of analyst forecast efficiency.[11] Consistent with the previous literature, we define prior abnormal returns (*PrAR*) as equal to the return between 10 days after the last quarterly earnings announcement to 10 days prior to the current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period.[12] Prior earnings changes (*PrEC*) are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the price at the beginning of the period, and prior forecast errors (*PrFE*) are the prior quarter's forecast error.

The remainder of this section proceeds as follows: we first present evidence on the existence of the tail and middle asymmetries in distributions of forecast errors conditional on the sign of prior news variables. We then analyze the role of the asymmetries in producing indications of analyst inefficiency in both summary statistics and regression coefficients and discuss the robustness of these findings. Next, we show the disproportionate impact of observations that comprise the asymmetries in generating evidence of serial correlation in analyst forecast errors. Finally, we discuss the shortcomings of econometric "fixes" that intentionally or unintentionally ameliorate the impact of one or both asymmetries on inferences concerning analyst forecast rationality.

3.1. The tail and middle asymmetries in forecast error distributions conditional on prior news variables

Tests of analyst forecast efficiency typically partition distributions of forecast errors based on the sign of the prior news to capture potential differences in analyst reactions to prior good versus prior bad news. Accordingly, before we review the

[11] Studies that examine the issue of current period forecast efficiency with respect to prior period realization of returns or earnings (e.g., Abarbanell, 1991; Easterwood and Nutt, 1999) commonly frame the question in terms of whether analysts over- or underreact to prior news. In contrast, studies that examine the issue of current period forecast efficiency with respect to analysts' own past forecast errors are generally limited to the question of whether there is significant serial correlation in lagged forecast errors, without regard to how the sign and magnitude of prior forecast errors affect that correlation.

[12] All reported results are qualitatively similar when prior abnormal returns are measured between 10 days after the last quarterly earnings announcement to either 30 days prior or 1 day prior to the current quarter earnings announcement.

statistical evidence, we first examine the features of forecast error distributions conditional on the sign of prior news variables. Panels A–C of Fig. 2, which depict the percentiles of the distributions of forecast errors conditional on the sign of each of the three prior news variables, show that prior bad news partitions are characterized by larger tail asymmetries than prior good news partitions for all prior news variables.

Panels A–C of Fig. 3—which depict the frequencies of forecast errors that fall in fixed subintervals of 0.025 within the range of -0.5 to $+0.5$ for *PrAR*, *PrEC*, and *PrFE*, respectively—show that prior good news partitions are characterized by larger middle asymmetries than prior bad news partitions for all three prior news variables.[13]

Together, Figs. 2 and 3 suggest that distributions of forecast errors conditional on the sign of prior news retain the characteristic asymmetries found in the unconditional distributions in Section 2. However, the likelihood of a subsequent forecast error falling into the middle asymmetry is greater following prior good news, while the likelihood of a forecast error falling into the tail asymmetry is greater following prior bad news.[14] Below we investigate the impact of the variation in the size of the asymmetries in distributions of forecast errors conditional on the sign of news on inferences about analyst inefficiency that are drawn from summary statistics (Section 3.1.1) and regression coefficients (Section 3.1.2).

3.1.1. Inferences about analyst efficiency from summary statistics

Panel A of Table 2 shows how the two asymmetries impact summary statistics, including means, medians, and the percentages of negative to positive forecast errors in distributions of forecast errors conditional on the sign of prior news. We begin with the case of prior bad news. Prior bad news partitions for all three variables produce significantly negative mean forecast errors (-0.195 for *PrAR*, -0.291 for *PrEC*, and -0.305 for *PrFE*), supporting an inference of analyst underreaction (i.e., the mean forecast is too high following bad news). The higher percentages of negative than positive forecast errors in the bad news partitions of each variable (e.g., 50% vs. 40% for negative *PrEC*) are also consistent with a tendency for analysts to underreact to prior bad news. The charts in Figs. 2 and 3 foreshadow these results. The relatively larger tail asymmetry in prior bad news partitions drives parametric means to large negative values. Similarly, the larger negative relative to

[13] The concentration of small (extreme) errors among positive (negative) prior returns news is not induced by scaling by prices that are systematically higher (lower) following a period of abnormal positive (negative) returns, since the middle and tail asymmetries are still present in distributions of unscaled forecast errors and errors deflated by forecasts.

[14] Abarbanell and Lehavy (2003a) report the same patterns in forecast error distributions conditional on classification of ranked values of stock recommendations, P/E ratio, and market-to-book ratios into high and low categories. It is certainly possible that some form of irrationality or incentive effect leads to different forecast error regimes on either side of a demarcation point of zero, and therefore coincidentally sorts the two asymmetries that are located on either side of a zero. However, the continued presence of relatively small but statistically influential asymmetries in the conditional distributions may overwhelm the researcher's ability to detect these incentive or behavioral factors, or may give the false impression that such a factor is pervasive in the distribution when it is not.

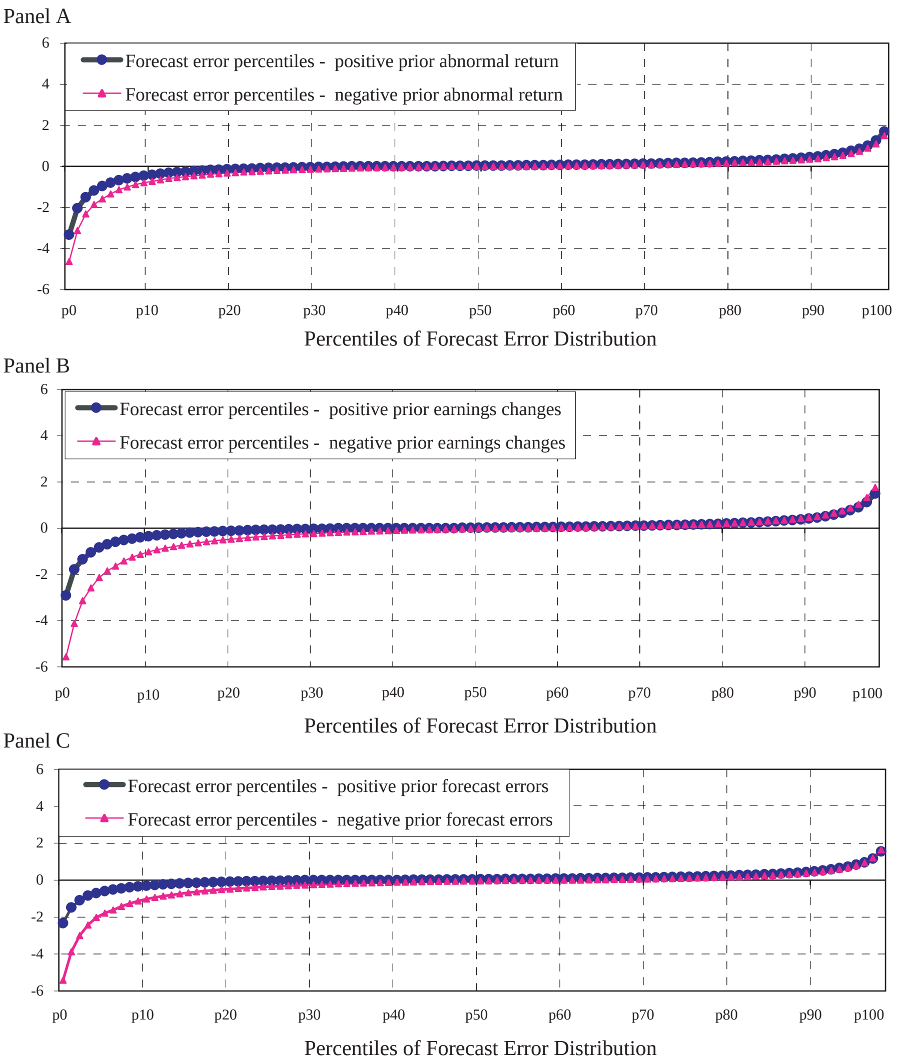
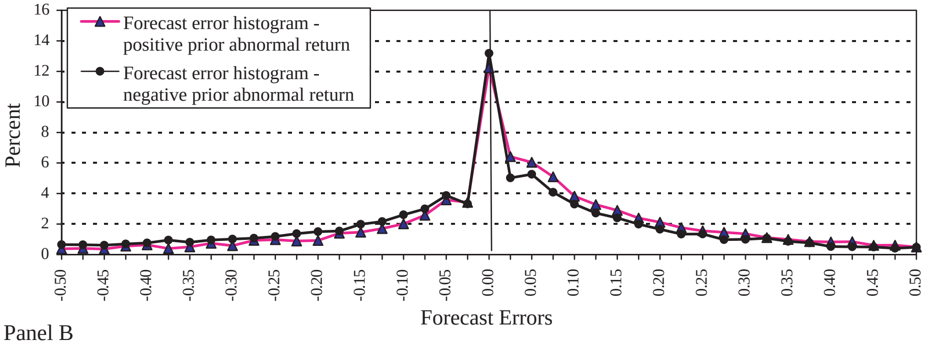


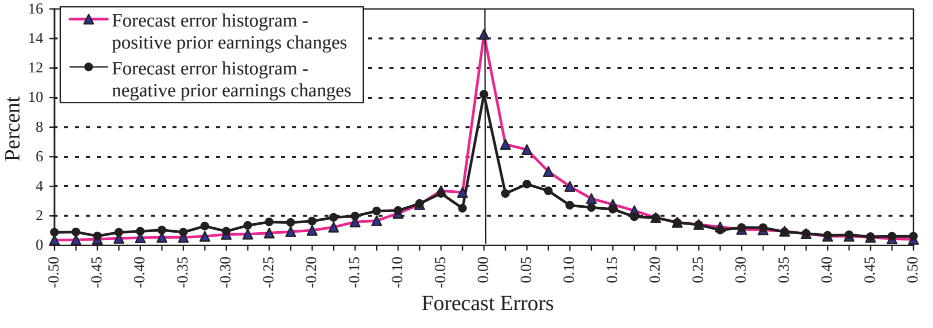
Fig. 2. Forecast error equals reported earnings minus consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Prior market-adjusted return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price.

positive tails account for greater overall frequencies of negative than positive errors, consistent with underreaction to bad news for all three variables. This is so even though prior bad news distributions of forecast errors for *PrAR* and *PrEC* are characterized by middle asymmetries, which, all else equal, tend to push the ratio of positive to negative errors toward values greater than 1.

Panel A



Panel B



Panel C

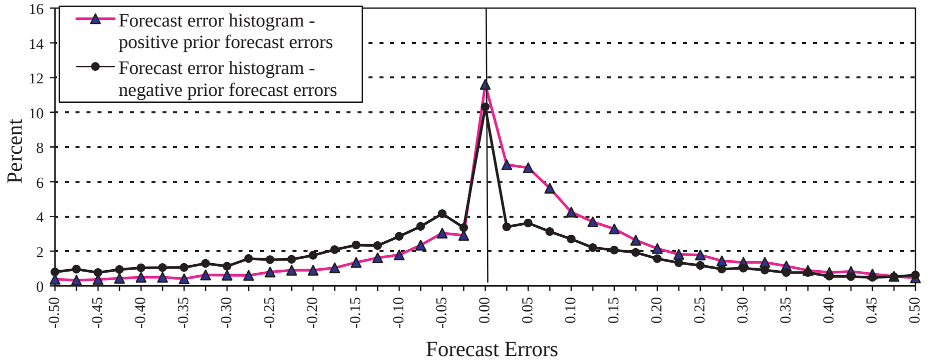


Fig. 3. Histogram of forecast errors by sign of prior abnormal returns (Panel A), prior earnings changes (Panel B), and prior forecast errors (Panel C). This figure presents the percentage of forecast error values in histogram intervals for observations within forecast error of -0.5 to $+0.5$ by sign of prior abnormal return (Panel A), prior earnings changes (Panel B), and prior forecast errors (Panel C). Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price.

Table 2
Mean, median, and frequency of forecast errors (Panel A), and ratio of positive to negative forecast errors in symmetric regions for bad (Panel B) and good (Panel C) prior news variables

Panel A: Mean, median, and frequency of forecast errors by sign of prior news variables

Statistic	Sign of prior abnormal return		Sign of prior earnings changes		Sign of prior forecast errors	
	Negative (1)	Positive (2)	Negative (3)	Positive (4)	Negative (5)	Positive (6)
Mean	-0.195^{*}	$-0.041^{*,\#}$	-0.291^{*}	$-0.036^{*,\#}$	-0.305^{*}	$0.017^{*,\#}$
Median	0.000	0.028	−0.015	0.020	−0.043	0.042
% Zero forecast errors	13%	12%	10%	14%	10%	11%
% Positive forecast errors	42%	54%	40%	52%	36%	59%
% Negative forecast errors	45%	34%	50%	34%	54%	30%
N	16,940	13,833	11,526	21,062	12,999	15,415

Panel B: Ratio of positive to negative forecast errors for negative *realizations of prior news*

Range of forecast errors	Negative prior abnormal return		Negative prior earnings changes		Negative prior forecast errors	
	Ratio of positive to negative FE (1)	% of total (2)	Ratio of positive to negative FE (3)	% of total (4)	Ratio of positive to negative FE (5)	% of total (6)
Overall	0.94	100	0.81	100	0.66	100
Forecast errors = 0		13		10		10
[−0.1, 0) & (0, 0.1]	1.39	27	1.26	21	0.94	23
[−0.2, −0.1) & (0.1, 0.2]	1.27	17	1.15	17	0.94	17
[−0.3, −0.2) & (0.2, 0.3]	0.99	10	0.93	11	0.75	10
[−0.4, −0.3) & (0.3, 0.4]	0.96	7	0.93	8	0.72	7
[−0.5, −0.4) & (0.4, 0.5]	0.73	5	0.74	6	0.59	5
[−1, −0.5) & (0.5, 1]	0.60	11	0.56	14	0.52	14
[Min, −1) & (1, Max]	0.29	10	0.28	14	0.24	14

Panel C: Ratio of positive to negative forecast errors for positive *realizations of prior news*

Range of forecast errors	Positive prior abnormal return		Positive prior earnings changes		Positive prior forecast errors	
	Ratio of positive to negative FE (1)	% of total (2)	Ratio of positive to negative FE (3)	% of total (4)	Ratio of positive to negative FE (5)	% of total (6)
Overall	1.58	100	1.53	100	1.99	100
Forecast errors = 0		12		14		11
[−0.1, 0) & (0, 0.1]	1.86	31	1.82	33	2.33	33
[−0.2, −0.1) & (0.1, 0.2]	1.89	18	1.85	18	2.42	19
[−0.3, −0.2) & (0.2, 0.3]	1.85	10	1.66	9	2.22	10
[−0.4, −0.3) & (0.3, 0.4]	1.70	6	1.49	6	2.03	7
[−0.5, −0.4) & (0.4, 0.5]	1.52	5	1.28	4	1.70	4
[−1, −0.5) & (0.5, 1]	1.25	10	1.17	9	1.44	10
[Min, −1) & (1, Max]	0.62	8	0.58	7	0.83	6

Panel A provides statistics on forecast errors (FE) by sign of prior abnormal return, prior earnings changes, and prior forecast errors. Panel B (Panel C) reports the ratio of positive to negative forecast errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors for negative (positive) prior abnormal returns, prior earnings changes, and prior forecast errors. Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by beginning-of-period price. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by price.

*Significantly different than zero at a 1% level or better.

#Mean forecast error for positive prior news variables is significantly different than mean forecast error for negative prior news variables at a 1% level or better.

The impact of the tail asymmetry on the inference of underreaction to prior bad news can be seen in Panel B of Table 2, which presents the number of observations in increasingly larger nonoverlapping symmetric intervals starting from zero for the three prior bad news partitions. Even though large errors in the intervals [min, -1) and (1, max] make up a relatively small percentage of the observations in the bad news distributions of *PrAR*, *PrEC*, and *PrFE* (10%, 14%, and 14%, respectively), errors of these absolute magnitudes comprise 3.45 ($=1/0.29$) 3.57 ($=1/0.28$), and 4.17 ($=1/0.24$) bad news observations for every good news observation, respectively.

Apparent consistency across summary statistical indicators of analyst underreaction to prior bad news does not carry over to the case of prior good news. The mean error for the good news partitions of *PrAR* and *PrEC* reported in columns 2 and 4 of Panel A of Table 2 are negative, consistent with analyst *overreaction* (i.e., the mean forecast is too high following good news), but is positive in the case of good news *PrFE*, suggesting *underreaction*. These mixed parametric results are attributable to the fact that tail asymmetries, although relatively small compared to their bad news counterparts, are still sufficiently large to produce negative mean errors for both prior good news partitions of *PrAR* and *PrEC* (see Fig. 2). However, they are not large enough to generate a negative median for these variables because, as seen in Panel C of Table 2, there is an even greater *frequency* of small positive errors associated with middle asymmetries in the good news partitions than for unconditional distributions (e.g., the ratio of positive errors to negative errors is 1.86 in the interval [-0.1, 0), (0, 0.1] of the *PrAR* partition but only 1.63 in that same interval of the unconditional distribution). The middle asymmetries are thus sufficiently large to offset relatively small tail asymmetries in these good news partitions, leading to indications of underreaction to good news in nonparametric statistics.[15]

3.1.2. Inferences about analyst efficiency from regression analysis

While means, medians, and ratios of positive to negative forecast errors are viable statistics from which to draw inferences of analyst inefficiency, most studies rely on slopes of regressions of forecast errors on prior news variables. The most persistent findings from such regressions are significant positive slope coefficients that are consistent with overall analyst *underreaction* to prior news realizations. To examine

[15] In this study, as in any study that partitions prior news variables by sign, we treat all prior variables as if they were interchangeable for the purposes of drawing inferences concerning a general tendency toward analyst inefficiency. Clearly, partitioning on the sign of news is likely to lead to misclassification in the case of prior earnings news, since the average firm is *not* likely to have an expected change of zero. Moreover, both prior earnings changes and prior forecast errors entail the use of an earnings benchmark, which, as discussed in the next section, introduces another potential problem of classification associated with potential time-series correlations induced by earnings management. These are interesting issues worthy of further consideration. However, they do not preclude an analysis of how the tail and middle asymmetries in forecast error distributions have combined to generate inconsistent indications of analyst inefficiency in the existing literature. If anything, these issues further strengthen the case for adopting the approach of identifying salient features of distributions of forecast errors in an effort to develop more precise hypotheses and design more appropriate empirical tests.

Table 3
Slope coefficients from OLS and rank regressions of forecast errors on prior news variables

	Explanatory variable					
	Prior abnormal return		Prior earnings changes		Prior forecast errors	
	OLS	Ranked	OLS	Ranked	OLS	Ranked
Overall	0.744	0.162	0.819	0.160	0.238	0.253
	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Prior bad news	1.602	0.213	2.306	0.130	0.231	0.265
	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Prior good news	0.089	0.199	−0.835	0.157	0.045	0.170
	0.28	<0.01	0.01	<0.01	0.11	<0.01

This table reports slope coefficient estimates from OLS and rank regressions of forecast errors on prior abnormal return, prior earnings changes, and prior forecast errors with the White-corrected p-values. Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by beginning-of-period price. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by price.

the effect of the two asymmetries on this inference, we first estimate the slope coefficients for separate OLS and rank regressions of forecast errors on *PrAR*, *PrEC*, and *PrFE*. After applying White corrections suggested by the regression diagnostics, the estimates, as shown in the first row of Table 3, confirm that the typical finding reported in the prior literature of overall underreaction holds for all three prior news variables in our sample, inasmuch as all three coefficients are positive and reliably different from zero. Similarly, rank regressions produce significant positive slope coefficients in the case of all three prior news variables.

Next, we compare the inferences from regression slope coefficients estimated by the sign of prior news to assess their consistency with the parametric and nonparametric evidence presented in Panel A of Table 2 and the preceding regression results for the overall samples. These results are presented in Table 3. Consistent with regression results for the overall sample, prior bad news partitions of all three variables produce OLS and rank slope coefficients that are significantly positive, indicating once again analyst underreaction to prior bad news. These results are consistent with indications of underreaction in both the parametric and nonparametric summary statistics associated with all three bad news partitions reported in Panel A of Table 2. In sharp contrast, however, regression results for the prior good news partitions generate inconsistent indications across both OLS and rank regression slope coefficients and across prior news variables. The OLS slope coefficient is positive but insignificant in the case of good news *PrAR* and *PrFE*, resulting in a failure to reject efficiency in these cases, but it is reliably negative for the good news *PrEC* variable, consistent with analyst *overreaction* to prior good earnings news. That is, OLS performed on the prior good news partitions of forecast errors produces *no* evidence of apparent analyst underreaction observed both in the overall samples and in the prior bad news partitions. In contrast, and adding to the ambiguity, rank regressions do produce reliably positive slope coefficients consistent with underreaction for all three prior good news variables. This finding is also consistent with the rank regression results for both the overall samples and the prior bad news partitions for all three prior news variables that suggest analyst underreaction.

It is evident from the foregoing collection of parametric and nonparametric results that it is difficult to draw a clear inference regarding the existence and nature of analyst inefficiency with respect to prior news. These results are a microcosm of similar inconsistencies found in the literature on analyst efficiency with respect to prior news, examples of which are discussed below. In keeping with our goal of assessing the extent, to which theories that predict systematic errors in analysts forecasts are supported by the evidence, we next delve further into the robustness of specific findings concerning analyst-forecast efficiency. As in the case of inferences on bias in analysts' forecasts, we find inconsistencies and a lack of robustness of evidence, which are linked to the relative size of the two asymmetries present in forecast error distributions.

3.2. How robust is evidence of analyst underreaction to bad news?

To further isolate the disproportional influence of the asymmetries on statistics, we examine the relation between forecast errors and prior news variables in finer partitions of the prior news variables. Our goal is to demonstrate that while the statistical indications of analyst underreaction to prior bad news are largely consistent in Tables 2 and 3, the phenomenon is not robust in the distribution of forecast errors. Fig. 4 depicts the percentiles of the distributions of forecast errors for the lowest, highest, and the combined distribution of the 2nd through the 9th decile of each prior news variable. One pattern evident in all of the panels is that the most extreme prior bad news decile is always associated with the most extreme negative forecast errors.

The effect of this association is evident in Fig. 5, which summarizes the mean and median forecast errors by decile of prior news for all three variables: The largest negative mean error by far is produced in the 1st decile of all prior news variables. This finding helps explain why overall bad news partitions of prior news yield parametric means that are always consistent with analyst underreaction.[16]

To gauge the effect of observations in the lowest prior news decile (which, as seen in Fig. 4, are associated with extreme negative forecast errors), we reestimate the

[16] Furthermore, in unreported results we find that OLS regressions by individual deciles produce significant positive coefficients in *only* the 1st decile among all deciles associated with prior bad news for all three prior variables. The combination of greater (lower) variation in the independent variable and a strong linear (nonlinear) relation between prior news and forecast errors in the first decile (other deciles) contribute to these results, as we discuss later.

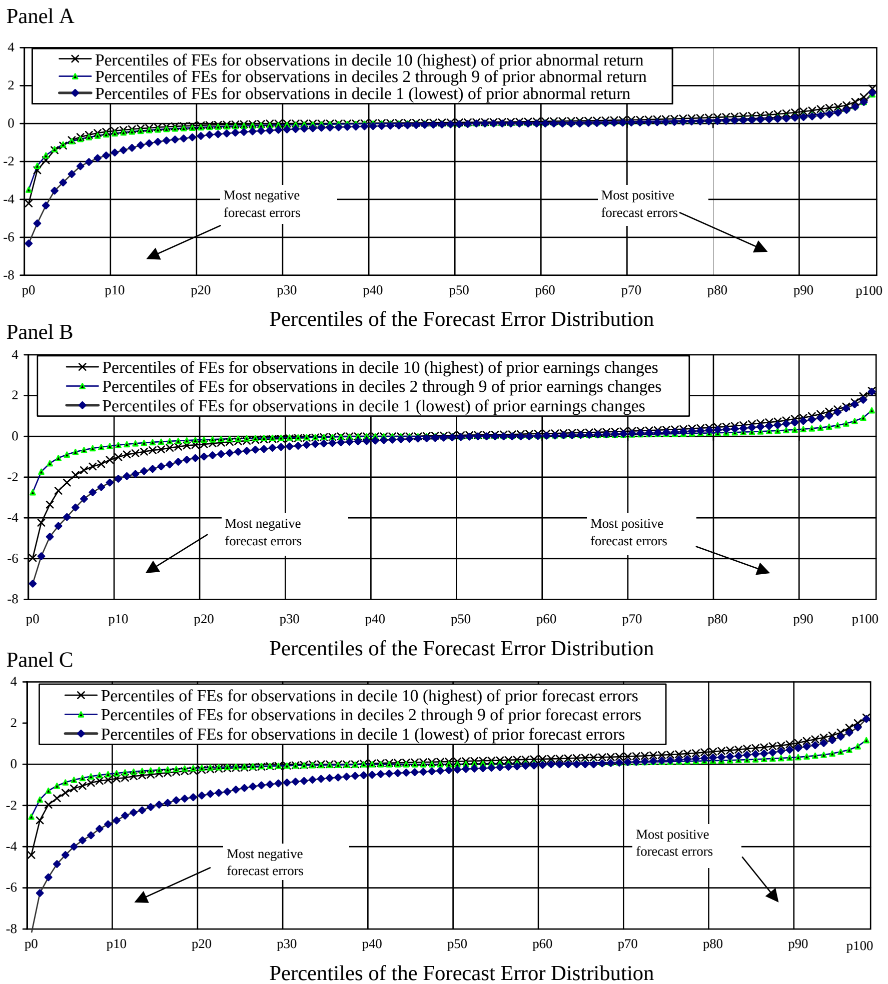


Fig. 4. The tail asymmetry in forecast errors within selected deciles of prior news variables. This figure depicts percentiles of quarterly distributions of analysts' forecast errors that fall in selected deciles (lowest, highest, and the combined distribution of the 2nd through the 9th decile) of prior abnormal returns (Panel A) prior earnings changes (Panel B) and prior forecast errors (Panel C). Forecast error equals reported earnings minus consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Prior market-adjusted return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price.

OLS regressions for the overall sample after excluding observations in this decile (unreported in the tables). We find that removing the 1st decile of prior news results in declines in the overall coefficients from values of 0.744, 0.819, and 0.238, to values

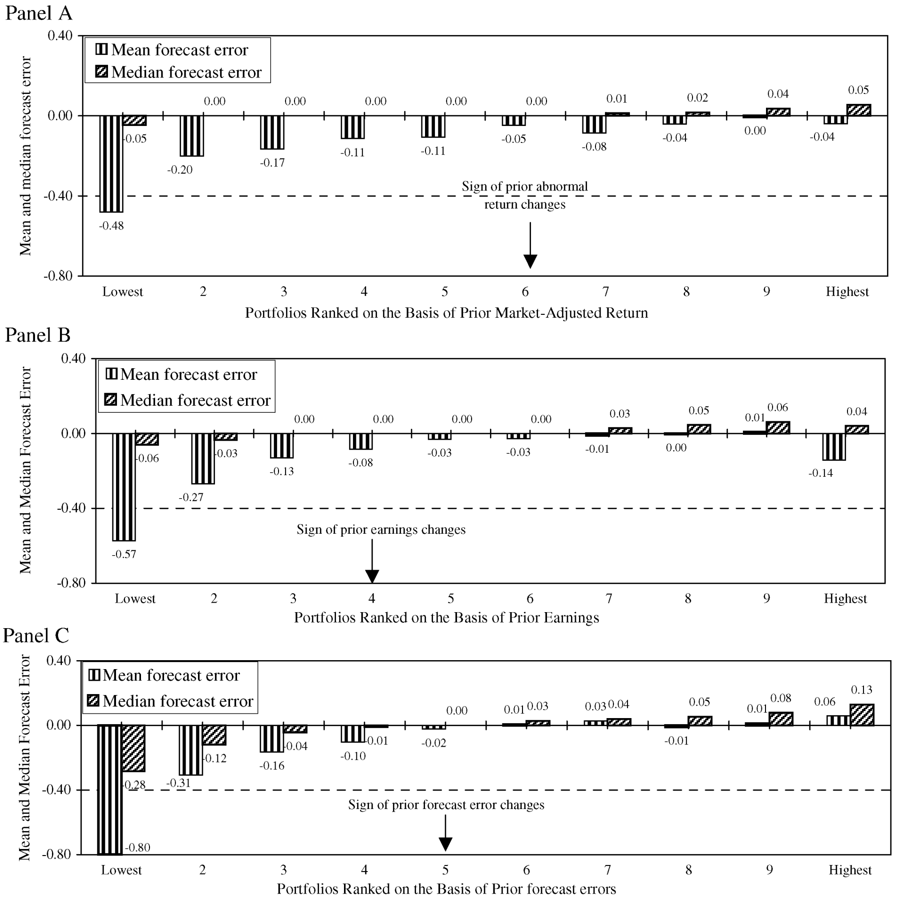


Fig. 5. Mean and median forecast errors by decile ranking of prior abnormal return (Panel A), prior earnings changes (Panel B), and prior forecast errors (Panel C). This figure depicts mean and median forecast errors for portfolios ranked on the basis of prior abnormal return (Panel A), prior earnings changes (Panel B), and prior forecast errors (Panel C). Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by price.

of 0.380, −0.559, and 0.194, for *PrAR*, *PrEC*, and *PrFE*, respectively, and *t*-statistics are significantly reduced in each case. Removal of individual deciles 2–9 before reestimating the regressions leads to virtually no change in the coefficients for all three prior news variables, whereas removal of the 10th decile actually leads to increases in the coefficients for all three variables. Notably, the disproportionate influence of extreme forecast error observations associated with extreme prior news is an effect that is not specifically predicted by extant behavioral or incentive-based theories of analyst inefficiency.[17]

The middle asymmetry also contributes, albeit more subtly than the tail asymmetry, to producing OLS regression coefficients that are consistent with underreaction to bad news. As seen in the first row of Panels A–C of Table 4 ("Overall"), which presents the ratio of positive to negative forecast errors by deciles of all three prior news variables, the percentage of positive errors increases as prior news improves. Consider, for example, in Panel A, the evidence for the first 5 deciles of *PrAR*, which only pertain to prior bad news realizations. The steadily increasing rate of small positive errors as *PrAR* improves will contribute to a positive slope coefficient in OLS regressions of forecast errors on prior bad news, reinforcing an inference of underreaction from this statistic. The concern raised by evidence in the remaining rows of Panel A of Table 4 is that less extreme prior bad news generates increasingly higher incidences of small positive versus small negative forecast errors—that is, observations that represent exactly the opposite of analyst underreaction.

Finally, recall that nonparametric statistics, including percentages of negative errors, rank regression slopes, and medians, also provide consistent indications of analyst underreaction to bad news. The nonparametric evidence in Panel A of Table 4 suggests however that this finding is also not as robust as it first appears. In the case of *PrAR*, for example, only the two most extreme negative deciles are associated with a reliably higher frequency of negative errors, which would not be expected if analyst underreaction to bad news was a pervasive phenomenon. In fact, there is a monotonic increase in the rate of positive to negative errors in the deciles that contain bad news realizations, with the 3rd decile containing a statistically equal number of each, and deciles 4–6 containing a reliably *greater* number of positive than negative errors.[18] Thus, observations that form the tail asymmetry, which is most pronounced in extreme bad news *PrAR*, even have a disproportional impact on some nonparametric evidence of underreaction to bad news, including indications from medians, percentages of negative errors, and rank regressions.[19]

[17] It is not well recognized that the inference of underreaction to prior bad news generated by the parametric tests favored in the literature is common to all prior news variables and is always driven by the concentration of extreme negative errors associated with extreme prior bad news. This conclusion can be drawn from studies investigating over/underreaction to prior returns (see, e.g., Brown et al., 1985; Klein, 1990; Lys and Sohn, 1990; Abarbanell, 1991; Elgers and Murray, 1992; Abarbanell and Bernard, 1992; Chan et al., 1996) and studies investigating over/underreaction to prior earnings changes (see, e.g., De Bondt and Thaler, 1990; Abarbanell and Bernard, 1992; Easterwood and Nutt, 1999).

[18] The 6th decile of *PrAR* includes small negative, small positive, and a limited number of zero observations. The demarcation point of zero occurs in the 4th decile of *PrEC*, reflecting a greater likelihood of positive earnings changes than negative earnings changes. The demarcation occurs in the 5th decile of *PrFE*, reflecting both a high percentage of zero prior forecast errors as well as the higher incidence overall of positive versus negative errors associated with the middle asymmetry. As suggested in footnote 15, simply partitioning prior news at the value of zero (as is done in the literature) may not lead to appropriate comparisons with respect to analyst efficiency across prior news variables in all situations.

[19] Recall that rank regressions of forecast errors and prior news produce large positive and significant slope coefficients, consistent with underreaction to bad news prior returns even though the incidence of positive errors is equal to or greater than the incidence of negative forecast errors in all but the most

Table 4
Ratio of small positive to small negative forecast errors in symmetric regions by decile ranking of prior abnormal return (Panel A), prior earnings changes (Panel B), and prior forecast error (Panel C)

Range of forecast errors	Lowest	2	3	4	5	6	7	8	9	Highest
Panel A: Ratio of small positive to small negative forecast errors and percentage of total decile observations within deciles of prior abnormal return										
Overall	0.66	0.78	0.97	1.08	1.17	1.27	1.33	1.39	1.76	2.12
[−0.1, 0) & (0, 0.1]	1.39	1.12	1.35	1.51	1.53	1.61	1.66	1.75	1.84	2.43
	24%	30%	32%	34%	35%	36%	38%	36%	34%	31%
[−0.2, −0.1) & (0.1, 0.2]	1.11	1.16	1.26	1.24	1.49	1.53	1.46	1.54	2.41	2.60
	18%	19%	21%	19%	20%	21%	20%	20%	21%	21%
[−0.3, −0.2) & (0.2, 0.3]	0.75	0.83	0.99	1.15	1.14	1.31	1.72	1.56	2.02	2.64
	10%	11%	11%	11%	12%	12%	11%	12%	12%	11%
Panel B: Ratio of small positive to small negative forecast errors and percentage of total decile observations within deciles of prior earnings changes										
Overall	0.75	0.77	0.86	0.91	1.16	1.53	1.83	1.87	1.83	1.45
[−0.1, 0) & (0, 0.1]	1.52	1.30	1.18	1.14	1.38	2.10	2.36	2.07	2.00	1.98
	16%	21%	28%	41%	56%	54%	45%	33%	25%	18%
[−0.2, −0.1) & (0.1, 0.2]	1.25	1.15	1.11	1.08	1.29	1.57	2.24	2.54	2.20	1.91
	13%	19%	21%	23%	19%	20%	24%	25%	22%	15%
[−0.3, −0.2) & (0.2, 0.3]	0.97	0.98	0.91	0.79	0.93	1.19	2.03	2.17	1.98	2.19
	9%	12%	13%	12%	7%	9%	11%	13%	13%	11%
Panel C: Ratio of small positive to small negative forecast errors and percentage of total decile observations within deciles of prior forecast errors										
Overall	0.53	0.58	0.70	0.74	1.32	2.25	2.06	1.91	1.95	1.82
[−0.1, 0) & (0, 0.1]	1.10	0.90	0.91	0.87	1.50	3.02	2.22	2.05	2.09	1.65
	8%	15%	24%	37%	65%	58%	46%	33%	24%	13%
[−0.2, −0.1) & (0.1, 0.2]	1.27	0.94	0.88	0.90	1.16	2.17	2.68	2.59	2.75	1.99
	10%	17%	23%	25%	18%	21%	24%	25%	23%	16%
[−0.3, −0.2) & (0.2, 0.3]	0.90	0.71	0.69	0.64	1.28	1.69	2.16	2.66	2.20	2.32
	9%	12%	14%	11%	7%	8%	10%	14%	15%	13%

This table reports the ratio of small positive to small negative forecast errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors and the percentage of observations that fall in these intervals of the total nonzero forecast errors in that decile. Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by price.

(*footnote continued*)
extreme deciles of bad news *PrAR*. This occurs because the most negative ranks of *PrAR* are paired with the most negative forecast errors, which when combined with the increasing incidence of pessimistic errors as bad news becomes less extreme (in principle, overreaction), accounts for an overall positive association in the rank slope coefficient that is consistent with apparent underreaction.

3.3. How robust is the evidence of misreaction to prior good news?

As seen in Tables 2 and 3, evidence can be found for either analyst underreaction or overreaction to prior good news, depending on the statistical approach and/or prior variable on which the researcher focuses. Our goal in this section is to examine the robustness of parametric evidence of analyst overreaction and nonparametric evidence of analyst underreaction to good news.

In Panel A of Fig. 4, the most extreme prior good news decile in the case of *PrAR* does not display a tail asymmetry substantially different from the combined deciles 2–9. In contrast, in the case of *PrEC* (in Panel B) the most extreme positive decile actually exhibits the second largest degree of tail asymmetry inasmuch the combined inner decile distribution (deciles 2–9) has a considerably smaller tail asymmetry. In the case of *PrFE*, depicted in Panel C, the most extreme positive decile displays a slightly greater degree of tail asymmetry than the combined deciles 2–9. Thus, although the tail asymmetry is always present in extreme prior good news deciles, there is considerable variation in the degree of tail asymmetry across extreme good news realizations of prior news variables—a phenomenon that once again is not contemplated by general incentive and behavioral theories.

The statistical impact of variation in the degree of tail asymmetries in extreme good news deciles across prior variables is reflected in the mean forecast errors by decile presented in Fig. 5. Notably, as seen in Panel B, the relatively large tail asymmetry associated with extreme good news *PrEC* leads to a negative mean error in the 10th decile (i.e., overreaction), which aligns with the large tail asymmetry observed in Panel B of Fig. 4. In contrast, mean forecast errors for the good news *PrEC* deciles 5–9 are small and in many cases significantly positive (i.e., consistent with underreaction) because the tail asymmetry associated with these observations is small. The disproportional influence of the 10th decile of *PrEC* is also evident in regression results. In addition to being responsible for the only overall prior good news partition that produces a significant OLS slope coefficient, it is the only individual decile comprising good news for any variable that produces a significant slope coefficient (unreported in the tables). We note that removal of the 10th decile from the overall regression of forecast errors on *PrEC* leads to an increase in the slope coefficient from a value of 0.819 to 3.17, with a corresponding increase in the t-statistic. That is, the strong negative association between forecast errors and prior good news in this decile, which contributes disproportionately to the finding of overreaction to good news, also introduces severe nonlinearity in the overall regression.[20]

[20] The increasing rate of small positive errors as good news becomes more extreme contributes to positive slope coefficients in OLS regressions of forecast errors on prior good news. This is analogous to the impact of increasing rates of positive errors as bad news becomes less extreme, an effect more evident when the most extreme decile of good news is removed. The concern here, however, is that more extreme prior news leads to higher incidences of less extreme positive forecast errors—a phenomenon that is not only counterintuitive but is not predicted by extant incentive and behavioral theories of analyst inefficiency.

The most extreme good news *PrEC* decile is, therefore, largely responsible for the negative slope coefficient and the negative mean observed for good news *PrEC* partitions, suggesting the dominant influence of a small number of observations from the left tail of the distribution of forecast errors in producing parametric evidence of overreaction to good news prior earnings changes. Easterwood and Nutt (1999) refer to regression results that indicate a combination of underreaction to bad news and overreaction to good news as *generalized optimism*. From the evidence presented thus far it is clear that a small number of extreme negative forecast error observations associated with both extreme bad and extreme good news *PrEC* realizations are largely responsible for this finding. The question of the robustness of the finding of generalized optimism is magnified in the case of statistical indications of overreaction to good news because, as was reported in Table 2, good news *PrAR* and *PrFE* do not generate consistent parametric evidence of generalized optimism, even in the extreme deciles. This lends a "razor's edge" quality to the result that hinges on whether there is a sufficiently large number of extreme bad and good news realizations associated with extremely negative forecasts.[21] Furthermore, ambiguity in interpreting the evidence is introduced because there is no extant behavioral or incentive theory of analyst inefficiency that predicts that, when overreaction occurs, it will be concentrated among extreme prior news and come in the form of extreme analyst overreaction.

Finally, just as in the case of prior bad news, the presence of asymmetries also raises questions about the robustness of nonparametric evidence of analyst misreaction to prior good news. Recall from Section 3.1.1 that, in contrast to parametric statistics, nonparametric statistics suggested analyst *underreaction* to prior good news for all three prior news variables. The evidence in Tables 2 and 4 indicates that large middle asymmetries reinforce nonparametric indications of underreaction—in particular, the increasing relation between the magnitude of good news and the likelihood of small positive forecast errors, a relation that is monotonic in the case of *PrAR* and *PrFE*. Thus, the middle asymmetry, and its variation with the magnitude of prior good news, has a disproportionate impact on the inference of underreaction to good news from nonparametric statistics, including indications from medians, percentages of negative errors, and rank regressions. Notably, the percentage of positive forecast errors is substantially larger than the percentage of negative errors even in the most extreme *PrEC* decile. That is, the decile largely responsible for producing the only statistical evidence that analysts overreact to good news displays a strong tendency for errors that are consistent with underreaction.

3.4. The tail and middle asymmetries and serial correlation in analysts' forecasts

The preceding results indicate that regression evidence of underreaction is disproportionately influenced by apparent extreme underreaction to extreme bad

[21] Easterwood and Nutt (1999) eliminate the middle third of the prior earnings news distribution before estimating OLS slope coefficients, which provide the statistical support for their conclusion that analysts underreact to bad news and overreact to good news. Clearly, this test design gives even greater weight to observations that comprise the tail asymmetry.

prior news and is also impacted by the increase in the middle asymmetry as prior news improves. The asymmetries have important impacts on alternative (to regression) tests of analyst inefficiency in the literature. For example, as mentioned earlier, the analysis of the relation between current and prior forecast errors is typically not couched in terms of over- or underreaction to signed prior news, but rather in terms of overall serial correlation in lagged analyst forecast errors (see, e.g., Brown and Rozeff, 1979; Mendenhall, 1991; Abarbanell and Bernard, 1992; Ali et al., 1992; Shane and Brous, 2001; Alford and Berger, 1999). These studies focus almost exclusively on parametric measures of serial correlation and primarily on the first lag, or consecutive period errors.

Table 5 presents the Pearson and Spearman correlation between consecutive quarterly forecast errors for the overall sample and within each of the deciles of current forecast errors. The mean correlations for the entire sample are statistically significant, with yearly averages of 0.15 and 0.22, respectively. Note that the first decile, which includes the observations in the extreme left tail that are associated with the tail asymmetry, produces the greatest Pearson and Spearman correlations of 0.17 and 0.19, respectively. In contrast, the correlations in all other deciles are much smaller and most often statistically insignificant in the case of the Pearson measure. It is interesting to note that if distributions of forecast errors were symmetric, then forming deciles on the basis of current forecast errors (a procedure only followed in Table 5) would be expected to attenuate, relative to the overall sample serial correlation, the estimated correlation in every decile. However, the facts that correlation is not attenuated in the most extreme negative forecast error decile (in fact, it is larger than the overall correlation) and that the Pearson correlation is insignificant in the most extreme positive forecast error decile are additional indications of the important role the tail asymmetry plays in the findings of serial correlation. We note that when the deciles are formed based on *prior* forecast errors (that is they are sorted on the independent variable, as is done in all other tests performed in the paper) we still find that Pearson correlations are highest in the most extreme negative forecast error decile.[22]

Finally, we note that the strongest Spearman correlations in the table, other than the most extreme negative decile of current forecast errors, are found in deciles 6 and 7, i.e., those with a high concentration of current and prior small pessimistic forecast errors. The evidence is also inconsistent with what would be expected based on forming deciles on current forecast errors, where correlation in the middle deciles would be driven to zero. The higher correlations in deciles 6 and 7 are found whether deciles are formed on current or prior forecast errors. The evidence suggests the need for further exploration into the role of observations in the middle asymmetry in producing estimated serial correlation consistent with apparent analyst under-reaction to their own forecast errors.

[22] It is also interesting to note from columns 4 and 5 that the first decile is not only associated with the largest mean values for current forecast errors, but is also associated with the largest mean value among the prior (i.e., lagged) forecast error deciles.

Table 5
Serial correlation in consecutive-period forecast errors

Decile ranking of forecast errors (1)	Pearson correlation in consecutive forecast errors (2)	Spearman correlation in consecutive forecast errors (3)	Mean forecast errors (4)	Mean prior quarter forecast errors (5)
Lowest	0.17#	0.19#	−2.08	−0.79
2	0.04&	0.07#	−0.44	−0.26
3	0.03	0.06#	−0.17	−0.12
4	0.06#	0.05&	−0.06	−0.04
5	0.06#	0.03&	0.00	−0.07
6	−0.01	0.09#	0.03	0.04
7	0.01	0.08#	0.08	0.04
8	−0.02	0.04&	0.15	−0.01
9	0.00	0.04&	0.29	0.02
Highest	0.00	0.04&	0.90	−0.12
Overall	0.15#	0.22#	−0.13	−0.13

This table reports the Pearson and Spearman correlation coefficients and means of current and prior quarter forecast errors *within* deciles of the ranked (current) forecast error distribution. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by beginning-of-period price.
#(&) Represents a statistically significant correlation at a 1% (5%) level.

3.5. Summary and implications of the tail and middle asymmetries on inferences of analyst efficiency

An important conclusion from the analysis of conditional forecast error distributions is that the sign of prior news variables sorts observations from the tail and middle asymmetries in a manner that (1) reinforces the inference of underreaction found in parametric statistics for all prior *bad* news partitions, an inference that is largely the result of the dominant impact of the tail asymmetry; and (2) can create offsetting or reinforcing effects that contribute to producing conflicting signs of means and regression slope coefficients within and across different prior *good* news partitions of the variables. Thus, the presence of middle and tail asymmetries in conditional distributions of forecast errors helps explain why evidence of underreaction to bad news appears to be so robust in the literature while evidence of under- and overreaction to good news is not. Attenuation of means and slope coefficients due to the relatively greater impact of the middle asymmetry in good news distributions of forecast errors also helps explain why, in every study to date that employs parametric tests and concludes that analysts' forecasts are inefficient, the magnitude of misreaction to bad news is always found to be greater than the magnitude of misreaction to good news.

It is tempting to infer from the insignificance of slope coefficients pertaining to regressions of forecast errors on prior news generated for some good news partitions reported in Table 3 and in all inner deciles of distributions of all prior news variables that, apart from cases of extreme prior news, analysts produce efficient forecasts (see, footnote 16). However, the sensitivity of statistical findings in prior good news partitions documented above suggests that we exercise caution in reaching this conclusion. Results in Fig. 4 and Table 4, along with unreported results, verify that all decile partitions of *PrAR* and *PrEC* are characterized by both middle and tail asymmetries, and that every good (bad) news decile of *PrFE* is characterized by a middle (tail) asymmetry. While it is possible that failure to reject zero slope coefficients in the inner deciles is the result of a general tendency for analyst forecasts to be efficient when prior news is not extreme, we must concede the possibility that the lower variation in the independent variable and small numbers of observations associated with tail and middle asymmetries *within deciles* combine to produce nonlinearities and lower power in a manner that obscures evidence of analyst inefficiency. That is, slicing up the data into greater numbers of partitions does not appear to eliminate the potential impact of both asymmetries in influencing inferences concerning the existence and nature of analyst inefficiency in parametric tests.[23]

The evidence in this section reveals how asymmetries can produce and potentially obscure indications of analyst inefficiency, depending on the statistical approach adopted by the researcher. Next, we describe examples of procedures that (perhaps unintentionally) mitigate the impact of observations that comprise the asymmetries, but may not necessarily shed new light on the question of whether analysts' forecasts are efficient.

3.6. Data transformations, nonlinear statistical methods, and alternative loss functions

Apart from partitioning forecast errors in parametric tests and applying nonparametric tests, some studies implicitly or explicitly adjust the underlying data in order to attenuate the disproportional impacts and nonlinearities induced by the tail asymmetry. Two such approaches are truncating and winsorizing forecast errors. As in the case of inferences concerning bias discussed in Section 2, the effects of arbitrary truncations on inferences concerning analyst under- and overreaction can be significant. Keane and Runkle (1998), for example, argue that evidence of misreaction to prior earnings news is overstated as a result of uncontrolled cross-correlation in forecast errors. However, they explicitly state that their finding of efficiency—after applying GMM to control for bias in standard errors induced by cross-correlation—rests on having first imposed a

[23] Severe heteroscedasticity in the decile regression residuals are consistent with this argument. In addition, while we do not advocate arbitrary truncations of the data to mitigate the impact of the asymmetries we find that small symmetric truncations of tail observations within decile distributions similar to those described in the previous section for the unconditional distribution of forecast errors result in significant slope coefficients in many of the inner deciles of prior returns and prior earnings changes. Because small truncations of extreme observations reduce the number of observations in each decile and further reduce variation in the independent variable, it is possible that the statistical significance of the coefficients after truncation in these cases reflects the presence of analyst inefficiency and/or the elimination of the offsetting impact of the tail asymmetry in a manner that allows the middle asymmetry to dominate an inference of inefficiency.

sample selection criterion that results in the truncation of large forecast error observations in the extreme negative tail of the distribution. Their argument for doing so is that the Compustat reported earnings used to benchmark forecasts for such observations includes large negative transitory items that analysts do not forecast. Abarbanell and Lehavy (2002) show that tail asymmetries also characterize distributions of forecast errors based on the earnings reported by commercial forecast data sources such as I/B/E/S, Zacks, and First Call, which are, in principle, free of such special items. They also report a high correlation between the observations that fall into the extreme negative tail of the distribution of forecast errors calculated with Compustat-reported earnings and those that fall into the extreme negative tail of distributions calculated with earnings provided by forecast data services. Thus, it remains to be seen whether the finding of analyst forecast rationality continues to hold when GMM procedures are applied to untruncated distributions of forecast error based on "cleaned" reported earnings numbers rather than truncated distributions of forecast errors based on Compustat earnings.[24]

An alternative to arbitrarily truncating a subset of observations is to transform the entire distribution of forecasts, a common procedure used to eliminate nonlinearities, stabilize variances, or induce a normal distribution of forecast errors to avoid violating the assumptions of the standard linear model. For example, log and power transformations mitigate skewness and the disproportionate impact of extreme observations when the dependent variable is forecast errors. However, each type of transformation alters the structure of the data in a unique way, and it is possible for different transformations to yield different inferences concerning analyst inefficiency. That is, transformations of distributions of forecast error are not likely to lead to greater consensus in the literature unless strong a priori grounds for preferring one transformation to another can be agreed upon. Such grounds can only be found by gaining a better understanding of what factors are responsible for creating relevant features of the untransformed data—an understanding that in turn would require more exacting theories than have thus far been produced as well as more institutional research into the analysts' actual forecasting task.

Finally, instead of adapting the data to fit the model the researcher may choose to adapt the model to fit the data. Disproportionate variation in the degree of tail asymmetry as a function of the sign and magnitude of prior news suggests, at a minimum, that parametric tests of analyst inefficiency should be adapted to allow for the nonlinear relationship between forecast errors and prior news. For example, after Basu and Markov (2003) replaced the quadratic assumption in their standard OLS regression with a linear loss function assuming that analysts minimize absolute forecast errors, they found little evidence to support analyst inefficiency. Imposing this loss function has an effect similar to truncating extreme observations, since such

[24] We note that although arbitrarily truncating the dependent variable (e.g., Keane and Runkle, 1998) may seem to be a more egregious form of biasing a test, the evidence presented earlier suggests that arbitrarily truncating observations in the middle of the distribution of the prior earnings news (e.g., Easterwood and Nutt, 1999) can also create problems when researchers draw inferences about the tendency for analysts to misreact to prior news, inasmuch as this procedure can further accentuate the already disproportionate impact of the tail asymmetry.

observations are given less weight in the regression (as opposed to being removed outright from the distribution).[25]

Clearly there is something to be learned from examining how inferences change under different assumed loss functions. However, at this stage in the literature, the approach will have limited benefits for a number of reasons. First, while a logical case can be made for one loss function that leads to the failure to reject unbiasedness and efficiency, an equally strong case for a loss function that leads to a rejection of unbiasedness and efficiency can also be made, without either assumption being inconsistent with existing empirical evidence of how analysts are compensated. In such cases, the conclusion about whether analyst forecasts are rational will hinge on which assumption best describes analysts' true loss function—a subject about which we know surprisingly little.[26] Second, it is possible that some errors are actually partially explained by cognitive or incentive factors that are coincidental with or are exacerbated by other factors that give rise to the same errors the researcher underweights by assuming a given loss function. Finally, although assuming a given loss function—like the choice of alternative test statistics or data truncations—may lead to a statistical inference consistent with rationality, such an approach ignores the empirical fact that the two notable asymmetries are present in the distribution. Given their influence on inferences, providing compelling reasons for these asymmetries is a prerequisite for judging whether and in what circumstances incentives or cognitive biases induce analyst forecast errors.

In the next section we take a step toward understanding how the asymmetries in forecast error distributions arise by identifying a link between the presence of observations that comprise the two asymmetries and unexpected accruals included in the reported earnings used to benchmark forecasts. This link suggest the possibility that some "errors" in the distribution of forecast errors may arise only because the forecast was inappropriately benchmarked with *reported* earnings, when in fact the analyst had targeted a different earnings number.

4. Linking bias in reported earnings to apparent bias and inefficiency in analyst forecasts

4.1. Accounting conservatism and unexpected accruals

Abarbanell and Lehavy (2003a) argue that an important factor affecting the recognition of accounting accruals is the conservative bent of GAAP. Because

[25] Note that, as discussed earlier, there may be greater difficulty detecting irrationality (alternatively, a greater likelihood of failing to reject efficiency) using regression analysis once procedures that attenuate the impact of left tail observations are introduced because the middle asymmetry is still present.

[26] The fact that the evidence of misreaction to even extreme good news is mixed for different definitions of prior news and different parametric statistics presents a challenge to adapting behavioral theories to better fit the data. Unless we can identify a common cognitive factor that explains why differences in apparent misreaction depend on the extremeness of prior news, the empirical case for any form of generalized bias or inefficiency will hinge on a relatively small number of observations comprising the tail and middle asymmetries that are not predicted by the theory.

conservative accounting principles facilitate the immediate recognition of economic losses but restrict the recognition of economic gains, the maximum amount of possible income-decreasing accruals that a typical firm can recognize in a given accounting period will be larger than the maximum amount of income-increasing accruals (see, e.g., Watts, 2003). Table 6 provides evidence that supports this intuition.

The table presents selected summary statistics associated with cross-sectional distributions of firms' quarterly unexpected accruals over the sample period.[27] The mean unexpected accrual over the sample period is −0.217. While the distribution is negatively skewed, the median is 0.023 and the percentage of positive and negative unexpected accruals is nearly equal. It is evident from Table 6 that, while the unexpected accrual distribution is relatively symmetric in the middle, it is characterized by a longer negative than positive tail. For example, the magnitude of the average values at the 25th and 75th percentiles is nearly identical. However, symmetric counterpart percentiles outside these values begin to diverge by relatively large amounts, beginning with a comparison of the values at the 10th and 90th percentiles. The differences become progressively larger with comparisons of counterpart percentiles farther out in the tails. For example, the average 5th and 3rd percentile values are approximately 1.17 times larger than the average 95th and 97th percentiles, and the average value of the 1st percentile is 1.30 times larger than the average value of the 99th percentile. We stress that, although the percentile values of unexpected accruals vary from quarter to quarter, the basic shape of the distribution is similar in every quarter.

4.2. Linking unexpected accruals to asymmetry in tails of forecast error distributions

The measure of unexpected accruals we employ is based on historical relations known prior to the quarter for which earnings are forecast. Although the term "unexpected" is used, it is possible—in fact likely—that analysts will acquire new information about changes in the relations between sales and accruals that occurred during the quarter before they issue their last forecast for a quarter. Nevertheless, we can use the measure of unexpected accruals to identify, ex-post, cases in which significant changes in accrual relations did take place, and then assess whether the evidence is consistent with analysts' issuing a final forecast of earnings for the quarter either unaware of some of these changes or unmotivated to forecast them.

If analysts' forecasts do not account for the fact that some firms will recognize accruals placing them in the extreme negative tails of the distribution of unexpected accruals, then there will be a direct link between the negative tail of this distribution and the extreme negative tail of the forecast error distribution. The conjectured link

[27] Unexpected accruals reported in the tables are the measure produced by the modified Jones model applied to quarterly data (see Appendix A for calculations). To facilitate comparison with our forecast error measure, we express unexpected accruals on a per share basis scaled by price and multiplied by 100. As indicated earlier, the qualitative results are unaltered when we employ the unmodified Jones model and other estimation techniques found in the literature, including one that excludes nonrecurring and special items.

Table 6
Descriptive statistics on quarterly distributions of unexpected accrual, 1985–1998

Unexpected accrual	
Number of observations	33,548
Mean	−0.217
Median	0.023
Standard deviation	5.600
Skewness	−1.399
Kurtosis	16.454
% Positive	50.8
% Negative	49.2
% Zero	0.0
P1	−20.820
P3	−11.547
P5	−8.386
P10	−4.574
P25	−1.349
P75	1.350
P90	4.185
P95	7.148
P97	9.891
P99	15.945

This table reports descriptive statistics on quarterly distributions of unexpected accruals. Unexpected accruals are calculated using the modified Jones model as described in the appendix (expressed as unexpected accrual per share scaled by price and multiplied by 100).

is depicted in Fig. 6. The figure shows mean forecast errors in intervals of (+/−) 0.5% centered on the percentiles of unexpected accruals. For example, the mean forecast error corresponding to the Xth percentile of unexpected accruals is computed using observations that fall in the interval of $X-0.5$ to $X+0.5$ percentiles of the unexpected accruals distribution.

It is clear from Fig. 6 that extreme negative forecast errors are associated with extreme negative unexpected accruals. That is, the evidence suggests a direct connection between the tail asymmetry in the forecast error distribution (documented in earlier sections) and an asymmetry in tails of the unexpected accrual measure.[28] This link continues to be observed even when we employ consensus earnings estimates and reported earnings that are, in principle, stripped of

[28] Another example of this link relates to the evidence on serial correlation in forecast errors presented earlier. Recall from Table 5 that the most extreme prior forecast error decile is also associated with the most negative mean current forecast errors. In unreported results we find that this decile is also characterized by the largest negative lagged and current unexpected accruals observed for these deciles (whether forecast error deciles are formed on the current or prior forecast errors). Thus, consecutive quarters of large, negative unexpected accruals go hand-in-hand with consecutive quarters of extreme negative forecast error observations that, in turn, are associated with high levels of estimated serial correlation.

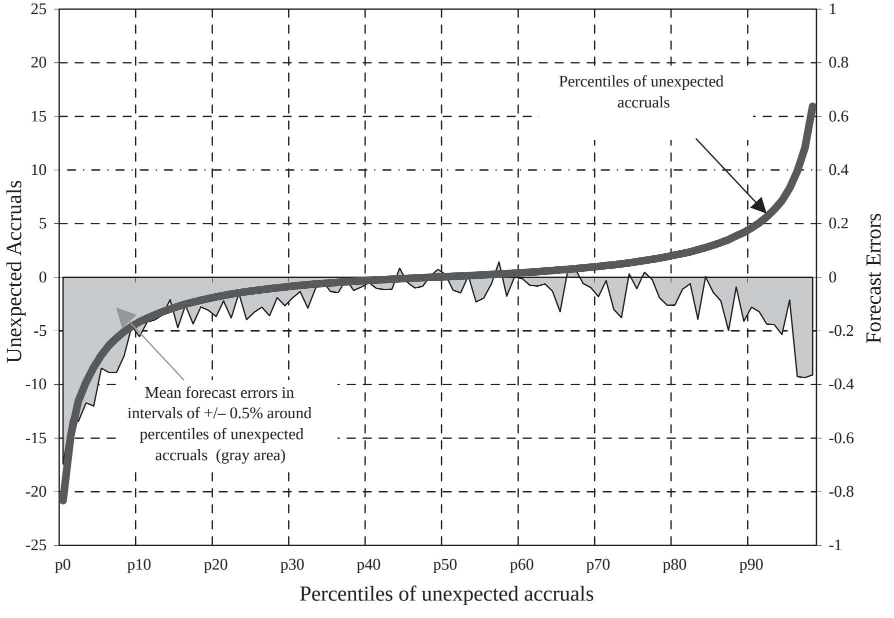


Fig. 6. Linking unexpected accruals and the asymmetry in tails of forecast error distributions. This figure depicts percentiles of unexpected accruals and mean forecast errors (gray area) in intervals of (+/−) 0.5% around unexpected accruals percentiles. For example, the mean forecast errors corresponding to the Xth percentile of unexpected accruals is computed using observations that fall in the interval of $X-0.5$ to $X+0.5$ percentiles of the unexpected accruals distribution. Forecast error equals reported earnings minus consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Unexpected accruals are the measure produced by the modified Jones model as described in the appendix (expressed as percentage of unexpected accrual per share scaled by price and multiplied by 100).

nonrecurring items and special charges (because Zacks indicates that analysts do not attempt to forecast these items), and a measure of unexpected accruals that also strips such items (see, Hribar and Collins, 2002). This suggests that an association exists between extreme negative accruals deemed "special or nonrecurring" and extreme negative accruals that do not fit this description. One possible reason for this association is that firms take an "unforecasted earnings bath," recognizing operating expenses larger than justified by the firm's actual performance for the period at the same time as they recognize large discretionary or nondiscretionary negative transitory operating and nonoperating items (see, Abarbanell and Lehavy, 2003b).

A second explanation for the association between large negative unexpected accruals and large negative forecast errors is that all the models of unexpected accruals examined in this study are prone to misclassifying nondiscretionary accruals as discretionary in periods when firms are recognizing large, negative transitory items. Combining the misclassification argument with a cognitive based argument that analysts react too slowly to extreme current performance would account for the observed link between unexpected accruals and forecast errors. While a more detailed analysis is beyond the scope of this paper, the evidence in Fig. 6 sheds additional light on the question of misclassification. It is seen in the figure that the largest percentiles of *positive* unexpected accruals are actually associated with fairly large negative mean forecast errors. The upside down U-shape that characterizes mean forecast errors over the range of unexpected accruals is inconsistent with a straightforward misclassification argument.[29] This is because if extreme positive unexpected accruals reflected misclassification in the case of firms that experience strong current performance, these would be the same cases in which analysts' forecasts would tend to underreact to extreme current good news and issue forecasts that fall short of reported earnings. The association between firm recognition of large negative transitory items and large negative operating items and the association between forecast errors and unexpected accruals are empirical phenomena that clearly deserve further exploration.

4.3. Linking unexpected accruals and the asymmetry in the middle of forecast error distributions

Table 7 provides evidence suggesting that unexpected accruals are also associated with the middle asymmetry in forecast error distributions. Column 2 presents a comparison of the ratio of positive to negative errors in narrow intervals centered on a zero forecast error (as reported in Panel B of Table 1) to the analogous ratio when forecast errors are based on reported earnings after "backing out" the realization of unexpected accruals for the quarter. In sharp contrast to the results reported in Table 1, the results in Table 7 indicate that after controlling for unexpected accruals, the number of small positive forecast errors *never* exceeds the number of small negative forecast errors in any interval. For example, the ratio of good to bad earnings surprises in the interval between [−0.1, 0) and (0, 0.1] is 1.63 (a value reliably different from 1) when errors are computed using earnings as reported by the firm, compared to 0.95 (statistically indistinguishable from 1) when errors are based on reported earnings adjusted for unexpected accruals. Thus, as in the case of the tail asymmetry, there is an empirical link between firms' recognition of unexpected accruals and the middle asymmetry. Given the impact of the tail and middle asymmetries on inferences concerning analyst bias and inefficiency described in Sections 2 and 3, researchers should take into account the role of unexpected accruals in the reported earnings typically used to benchmark forecast.

[29] The plot of *median* forecast errors around unexpected accrual percentiles also displays an upside down U-shape. However, as one might expect from the summary statistics describing the forecast error distributions in Table 1, the magnitude of these median errors is much smaller than mean errors, and large negative median forecast errors are only found in the most extreme positive and negative unexpected accrual percentiles.

Table 7
Linking unexpected accruals and the asymmetry in the middle of forecast error distributions

Range of forecast errors (1)	Ratio of positive to negative forecast errors based on *reported* earnings (2)	Ratio of positive to negative forecast errors based on earnings adjusted for unexpected accruals (3)
Overall	1.19*	0.96*
[−0.1, 0) & (0, 0.1]	1.63*	0.95
[−0.2, −0.1) & (0.1, 0.2]	1.54*	0.97
[−0.3, −0.2) & (0.2, 0.3]	1.31*	1.09
[−0.4, −0.3) & (0.3, 0.4]	1.22*	0.97
[−0.5, −0.4) & (0.4, 0.5]	1.00	0.99
[−1, −0.5) & (0.5, 1]	0.83*	0.95*
[Min, −1) & (1, Max]	0.40*	0.95*

This table provides the ratio of positive to negative forecast errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors. For example, the forecast error range of [−0.1, 0) & (0, 0.1] includes all observations that are greater than or equal to −0.1 and (strictly) less than zero and observations that are greater than zero and less than or equal to 0.1. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Earnings before unexpected accruals (used to compute the forecast error ratios in column 3) are calculated as the difference between reported earnings and the empirical measure of unexpected accruals.
*A test of the difference in the frequency of positive to negative forecast errors is statistically significant at or below a 1% level.

4.4. Explanations for a link between asymmetries in forecast error distributions and unexpected accruals

One general explanation for the link between unexpected accruals and the presence of asymmetries in forecast error distributions is that incentive or judgment factors that affect analysts' forecasts are exacerbated when estimates of unexpected accruals are likely to be unusual. For example, it is possible that cases of underreaction that appear to be concentrated among firms with the most extreme bad news reflect situations in which analysts have the weakest (strongest) incentives to lower (inflate) forecasts or suffer from cognitive obstacles that prevent them from revising their forecasts downward. At the same time, it has been argued in the accounting literature that unexpected accrual models produce biased downward estimates in exactly the same circumstances, i.e., when firms are experiencing extremely poor performance (see, e.g., Dechow et al., 1995).[30] This combination of

[30] The controversy over bias in unexpected accrual estimates relates to the issue of whether they truly reflect the exercise of discretion on the part of management. The conclusion that such measures are flawed is generally based on results from misclassification tests in which the maintained assumption is that historical data have not been affected by earnings management. This assumption can be challenged on logical grounds and, somewhat circularly, on the grounds that no evidence in the empirical literature supports this assumption.

potentially unrelated factors could account for the fact that extreme negative unexpected accruals accompany analysts' final forecasts for quarters characterized by prior bad news. Analogously, a higher incidence of small positive versus small negative errors as news improves is consistent with a greater likelihood of a *fixed* amount of judgment-related underreaction or incentive-based inflation of forecasts the better the prior news. The fact that unexpected accruals also appear to be related to the presence of the middle asymmetry may be coincidental to a slight tendency for unexpected accrual estimates to be positive in cases of firms experiencing high growth and positive returns (see, e.g., McNichols, 2000).[31]

Clearly there is a long list of possible combinations of unrelated factors that can simultaneously give rise to the two asymmetries in forecast error distributions and their apparent link to unusual unexpected accruals, which makes it difficult to pinpoint their source. Nevertheless, researchers still have good reason to consider these empirical facts when developing empirical test designs, choosing test statistics, and formulating and refining analytical models. One important reason is that if analysts' incentives or errors in judgment are responsible for systematic errors, it should be recognized that these factors appear to frequently produce very specific kinds of errors; i.e., small positive and extreme negative errors. To date, however, individual incentive and cognitive-based theories do not identify the economic conditions, such as extreme good and bad prior performance, that would be more likely to trigger or exacerbate incentive or judgment issues in a manner leading to exactly these types of errors. These explanations are also not easily reconciled with an apparent schizophrenia displayed by analysts who tend to slightly underreact to extreme good prior news with great regularity, but overreact extremely in a limited number of extreme good news cases. Finally, current behavioral and incentive-based theories do not account for actions undertaken by *firms* that produce reported earnings associated with forecast errors of the type found in the tail and middle asymmetries. Until such theories begin to address these issues it is not clear how observations that fall into the observed asymmetries should be treated in statistical tests of general forms of analyst irrationality. The identification of specific types of influential errors and their link to unexpected accruals documented in this paper provides a basis or expanding and refining behavioral and incentive theories of forecast errors.

A second reason for focusing on the empirical properties of forecast error distributions and their link to unexpected accruals is because it supports an alternative perspective on the cause of apparent forecast errors; i.e., the possibility that analysts either lack the ability or motivation to forecast discretionary biases in reported earnings. If so, then earnings manipulations undertaken to beat forecasts or to create reserves (e.g., earnings baths) that *are not* anticipated in analysts' forecasts

[31] McNichols (2000) argues that a positive association between unexpected accruals and growth reflects a bias in unexpected accrual models, but she does not perform tests to distinguish between this hypothesis and the alternative that high-growth firms are more likely to recognize a positive discretionary accrual to meet an earnings target, as argued in Abarbanell and Lehavy (2003a). We note that the presence of the middle asymmetry among firms with prior bad news returns and earnings changes is inconsistent with the misclassification argument.

may in part account for concentrations of small positive and large negative observations in distributions of forecast errors.[32] This suggests that evidence previously inferred to indicate systematic errors in analysts' forecasts might actually reflect the inappropriate benchmarking of forecasts.[33] An important implication of this possibility is that researchers may be formulating and testing new incentive and cognitive theories or turning to more advanced statistical methods and data transformations in order to explain forecast errors that are apparent, not real.

5. Summary and conclusions

In this paper we reexamine the evidence in the literature on analyst-forecast rationality and incentives and assess the extent to which extant theories for analysts' forecast errors are supported by the accumulated empirical evidence. We identify two relatively small asymmetries in cross-sectional distributions of forecast error observations and demonstrate the important role they play in generating statistical results that lack robustness or lead to conflicting conclusions concerning the existence and nature of analyst bias and inefficiency with respect to prior news. We describe how inferences in the literature have been affected, but these examples by no means enumerate all of the potential problems faced by the researcher using earnings surprise data. Our examples do demonstrate how some widely held beliefs about analysts' proclivity to commit systematic errors (e.g., the common belief that analysts generally produce optimistic forecasts) are not well supported by a broader analysis of the distribution of forecast errors. After four decades of research on the rationality of analysts' forecasts it is somewhat disconcerting that the most definitive statements observers and critics of earnings forecasters appear willing to agree on are ones for which there is only tenuous empirical support.

We stress that the evidence presented in this paper is not inconsistent with forecast errors due to analysts' errors in judgment and/or the effects of incentives. However, it does suggest that refinements to extant incentive and cognitive-based theories of systematic errors in analysts' forecasts may be necessary to account for the *joint* existence of both a tail asymmetry and a middle asymmetry in cross-sectional

[32] Abarbanell and Lehavy (2003b) offer theoretical, empirical, and anecdotal support for the assumption that analysts may not be motivated to account for or capable of anticipating earnings management in their forecasts. Based on this assumption they develop a framework in which analysts always forecast unmanaged earnings and firms undertake extreme income-decreasing actions or manipulations that leave reported earnings slightly above outstanding forecasts to inform investors of their private information. They describe a setting in which neither analysts nor managers behave opportunistically and investors are rational, where the two documented asymmetries in forecast error distributions arise and are foreshadowed by the sign and magnitude of stock returns before the announcement of earnings. In their setting, prior news predicts biases in the reported earnings benchmark, not biases in analysts' forecasts.

[33] Gu and Wu (2003) offer a variation on this argument suggesting that the analysts forecast the median earnings of the firm's ex-ante distribution, which also suggests that for some firms ultimate reported earnings (reports that differ from median earnings) are not the correct benchmark to use to assess whether analysts' forecasts are biased.

distributions of forecast errors. At the very least, researchers attempting to assess the descriptiveness of such theories should be mindful of the disproportionate impact of relatively small numbers of observations in the cross-section on statistical inferences.[34]

The evidence we present also highlights an empirical link between unexpected accruals embedded in the reported earnings benchmark to forecasts and the presence of the tail and middle asymmetries in forecast error distributions. Such biases in reported earnings benchmarks may point the way toward expanding and refining incentive and cognitive-based theories of analyst errors in the future. However, these results also raise questions about whether analysts are expected or motivated to forecast discretionary manipulations of reported earnings by firms. Thus, these results also highlight the fact that research to clarify the true target at which analyst forecasts are aimed is a prerequisite to making a compelling case for or against analyst rationality. Organizing our thinking around the salient properties of forecast error distributions and how they arise has the potential to improve the chaotic state of our current understanding of analyst forecasting and the errors analysts may or may not systematically commit.

Appendix A. The calculation of unexpected accruals

Our proxy for firms' earnings management, quarterly unexpected accruals, is calculated using the modified Jones (1991) model (Dechow et al., 1995); see Weiss (1999) and Han and Wang (1998) for recent applications of the Jones model to estimate quarterly unexpected accruals. All required data (as well as earnings realizations) are taken from the 1999 Compustat Industrial, Full Coverage, and Research files.

According to this model, unexpected accruals (scaled by lagged total assets) equal the difference between the predicted value of the scaled expected accruals ($NDAP$) and scaled total accruals (TA). Total accruals are defined as

$$TA_t = (\Delta CA_t - \Delta CL_t - \Delta Cash_t + \Delta STD_t - DEP_t)/A_{t-1},$$

where ΔCA_t is the change in current assets between current and prior quarter, ΔCL_t the change in current liabilities between current and prior quarter, $\Delta Cash_t$ the change in cash and cash equivalents between current and prior quarter, ΔSTD_t the change in debt included in current liabilities between current and prior quarter, DEP_t the current-quarter depreciation and amortization expense, and A_t the total assets.

[34] For example, given the recent attention in the literature to incentive factors that give rise to small, apparently pessimistic forecast errors (see footnote 5), it is important that researchers testing general behavioral theories understand that the middle asymmetry has the ability to produce evidence consistent with cognitive failures or, potentially, to obscure it. Similarly, the tail asymmetry has played a role in producing both parametric and nonparametric evidence that supports incentive-based theories of bias and inefficiency. However, such theories identify no role for extreme news or extreme forecast errors in generating predictions and do not acknowledge or recognize their crucial role in providing support for hypotheses.

The predicted value of expected accruals is calculated as

$$NDAP_t = \alpha_1(1/A_{t-1}) + \alpha_2(\Delta REV_t - \Delta REC_t) + \alpha_3 PPE_t,$$

where ΔREV_t is the change in revenues between current and prior quarter scaled by prior quarter total assets, ΔREC_t the change in net receivables between current and prior quarter scaled by prior quarter total assets, and PPE_t the gross property plant and equipment scaled by prior quarter total assets.

We estimate the firm-specific parameters, α_1, α_2, and α_3, from the following regression using firms that have at least ten quarters of data:

$$TA_{t-1} = a_1(1/A_{t-2}) + a_2\Delta REV_{t-1} + a_3 PPE_{t-1} + \varepsilon_{t-1}.$$

The modified Jones model resulted in 35,535 firm-quarter measures of quarterly unexpected accruals with available forecast errors on the Zacks database.

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Heard on the Street
Wall Street's Missed Expectations

By Liam Denning
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[Financial Analysis and Commentary]

Wall Street's sell-side analysts are a famously Panglossian tribe. But it turns out that they are actually too pessimistic when it comes to predicting company earnings, particularly in the wake of recession.

With 172 of the S&P 500's members having so far reported quarterly earnings,143 have beaten their consensus forecast, according to data collated by Thomson Reuters. On average, their numbers came in 21% above the **Street's** collective wisdom.

Less than 40% of theindex's members have reported, so the current score of 83% having beaten forecasts -- easily the highest for any quarter since at least 1999 -- may not stand. But having a high percentage of companies beat the Street isn't unusual. Thomson's data show that, on average, 64% of companies have done so in any given quarter since the start of 1999, compared with 18% that miss. The average earnings "surprise" is 2%, although these data swing erratically.

This is less surprising than it appears. Corporate management, for better or worse, go to great lengths to guide analysts toward the right numbers. After all, the last thing you want to do is deliver a nasty surprise. Just ask Ingersoll Rand, which **missed** the consensus forecast by 11% on Friday and saw its shares plunge 8.5% at one point.

Analysts are also prone to the same greed and fear that fuel the financial markets' gyrations. The most optimistic quarter since 1999, in which only 52% of S&P 500 companies beat the consensus forecast, was the last three months of 2000, just as the tech bubble was turning to bust.

With that in mind, it is little wonder that pessimism has really taken hold recently, with the percentage of companies beating earnings forecasts well above average since the second quarter of 2009. But there could be more to this than mere psychology. So far this quarter, for example, 69% of S&P 500 companies that have reported have beaten revenue estimates, according to Thomson. The implication is that final demand is stronger than anticipated.

Tobias Levkovich of Citigroup points to the importance of labor. Corporate America cut costs rapidly as recession took hold. That helped offset some of the damage inflicted on earnings by falling sales. But the ranks of the unemployed weigh heavily on **expectations** for a recovery in sales. That leaves scope for surprisingly good revenue numbers, relative to estimates, which in turn provides great operating leverage at the profit line, given earlier cost cutting.

So there is reason to suspect analysts' **expectations** will continue to be trumped by better results as the current reporting season progresses. But at some point, that unemployment rate has to fall if optimism is to be restored on a sustainable basis.

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Chapter 2

Introduction to the Cost of Capital

Defining the Cost of Capital

Ibbotson® Stocks, Bonds, Bills, and Inflation® (SBBI®) historical data can be used, along with other inputs, to make forecasts of the future, including estimates of the cost of capital. A cost of capital estimate seeks to discern the expected return, or forecast mean return, on an investment in a security, firm, project, or division.

The cost of capital (sometimes called the expected or required rate of return or the discount rate) can be viewed from three different perspectives. On the asset side of a firm's balance sheet, it is the rate that should be used to discount to a present value the future expected cash flows. On the liability side, it is the economic cost to the firm of attracting and retaining capital in a competitive environment, in which investors (capital providers) carefully analyze and compare all return-generating opportunities. On the investor's side, it is the return one expects and requires from an investment in a firm's debt or equity. While each of these perspectives might view the cost of capital differently, they are all dealing with the same number.

The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine the cost of capital. An investor contributes capital to a firm with the expectation that the business's future performance will provide a fair return on the investment. If past performance were the criterion most important to investors, no one would invest in start-up ventures. It should also be noted that the cost of capital is a function of the investment, not the investor.

The cost of capital is an opportunity cost. Some people consider the phrase "opportunity cost of capital" to be

The Ibbotson® SBBI® Data Series

SBBI Data Series	Series Construction	Index Components	Approximate Maturity
1. Large Company Stocks	S&P 500 Composite with dividends reinvested. (S&P 500, 1957–Present; S&P 90, 1926–1956)	Total Return Income Return Capital Appreciation Return	N/A
2. Ibbotson Small Company Stocks	Fifth capitalization quintile of stocks on the NYSE for 1926–1981. Performance of the DFA U.S. 9-10 Small Company Portfolio January 1982–March 2001. Performance of the DFA U.S. Micro Cap Portfolio April 2001–Present.	Total Return	N/A
3. Long-Term Corporate Bonds	Citigroup Long-Term High Grade Corporate Bond Index	Total Return	20 Years
4. Long-Term Government Bonds	A One-Bond Portfolio	Total Return Income Return Capital Appreciation Return Yield	20 Years
5. Intermediate-Term Government Bonds	A One-Bond Portfolio	Total Return Income Return Capital Appreciation Return Yield	5 Years
6. U.S. Treasury Bills	A One-Bill Portfolio	Total Return	30 Days
7. Consumer Price Index	CPI—All Urban Consumers, not seasonally adjusted	Inflation Rate	N/A

The series presented here are total returns and, where applicable or available, capital appreciation returns and income returns. A description of the Center for Research in Security Prices small stock data is found in Chapter 7, Firm Size and Return.

Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts

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■ 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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literature on financial analysts' forecasts (FAF). In Section II, models and data are discussed. Following a comparison of the results to historical risk premia, the estimates are subjected to economic tests of both their time-series and cross-sectional characteristics in Section III. Finally, conclusions are offered in Section IV.

I. Background and Literature Review

In establishing economic criteria for resource allocation, it is often convenient to use the notion of a shareholder's required rate of return. Such a rate (k) is the minimum level of expected return necessary to compensate the investor for bearing risks and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (e.g., bonds or other equities) and the riskiness of the stock. To isolate the effects of risk, it is useful to work in terms of a risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment.[1]

Lacking a superior alternative, investigators often use averages of historical realizations to estimate a benchmark "market" risk premium which then may be adjusted for the relative risk of individual stocks (e.g., using the CAPM or a variant). The historical studies of Ibbotson Associates [13] have been used frequently to implement this approach.[2] This historical approach requires the assumptions that past realizations are a good surrogate for future expectations and, as typically applied, that risk premia are constant over time. Carleton and Lakonishok [5] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

As an alternative to historical estimates, the current paper derives estimates of k, and hence, implied values of rp, using publicly available expectational data. This expectational approach employs the dividend growth model (hereafter referred to as the discounted cash flow or DCF model) in which a consensus measure of financial analysts' forecasts (FAF) of earnings is used as a proxy for investor expectations. Earlier works by Malkiel [17], Brigham, Vinson, and Shome [4], and Harris [12] have used FAF in DCF models, and this approach has been employed in regulatory settings (see Harris [12]) and suggested by consultants as an alternative to use of historical data (e.g., Ibbotson Associates [13, pp. 127, 128]). Unfortunately, the published studies use data extending to 1984 at the latest. Our paper draws on this earlier work but extends it through 1991.[3] Our work is closest to that done by Harris [12], who reviews literature showing a strong link between equity prices and FAF and supporting the use of FAF as a proxy for investor expectations. Using data from 1982 to 1984, Harris' results suggest that this expectational approach to estimating equity risk premia is an encouraging alternative to the use of historical averages. He also demonstrates that such risk premia vary both cross-sectionally with the riskiness of individual stocks and over time with financial market conditions.

II. Models and Data

A. Model for Estimation

The simplest and most commonly used version of the DCF model to estimate shareholders' required rate of return, k, is shown in Equation (2):

$$k = \left(\frac{D_1}{P_0}\right) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share. The limitations of this model are well known, and it is straightforward to derive expressions for k based on more general specifications of the DCF model.[4] The primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expectations of future perfor-

[1] Theoretically, i is a risk-free rate, though empirically its proxy (e.g., yield to maturity on a government bond) is only a "least risk" alternative that is itself subject to risk. In this development, the effects of tax codes on required returns are ignored.

[2] Many leading texts in financial management use such historical risk premia to estimate a market return. See, for example, Brealey and Myers [3]. Often a market risk premium is adjusted for the observed relative risk of a stock.

[3] See Harris [12] for a discussion of the earlier work and a detailed discussion of the approach employed here.

[4] As stated, Equation (2) requires expectations of either an infinite horizon of dividend growth at a rate g or a finite horizon of dividend growth at rate g and special assumptions about the price of the stock at the end of that horizon. Essentially, the assumption must ensure that the stock price grows at a compound rate of g over the finite horizon. One could alternatively estimate a nonconstant growth model, although the proxies for multistage growth rates are even more difficult to obtain than single stage growth estimates. Marston, Harris, and Crawford [19] examine publicly available data from 1982-1985 and find that plausible measures of risk are more closely related to expected returns derived from a constant growth model than to those derived from multistage growth models. These findings illustrate empirical difficulties in finding empirical proxies for multistage growth models for large samples.

mance. Without a ready source for measuring such expectations, application of the DCF model is fraught with difficulties. This paper uses published FAF of long-run growth in earnings as a proxy for g.

B. Data

FAF for this research come from IBES (Institutional Broker's Estimate System), which is a product of Lynch, Jones, and Ryan, a major brokerage firm.[5] Representative of industry practice, IBES contains estimates of (*i*) EPS for the upcoming fiscal years (up to five separate years), and (*ii*) a five-year growth rate in EPS. Each item is available at monthly intervals.

The mean value of individual analysts' forecasts of five-year growth rate in EPS will be used as a proxy for g in the DCF model.[6] The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. IBES requests "normalized" five-year growth rates from analysts in order to remove short-term distortions that might stem from using an unusually high or low earnings year as a base.

Dividend and other firm-specific information come from COMPUSTAT. Interest rates (both government and corporate) are gathered from Federal Reserve Bulletins and *Moody's Bond Record*. Exhibit 1 describes key variables used in the study. Data collected cover all dividend paying stocks in the Standard & Poor's 500 stock (S&P 500) index, plus approximately 100 additional stocks of regulated companies. Since five-year growth rates are first available from IBES beginning in 1982, the analysis covers the 113-month period from January 1982 to May 1991.

III. Risk Premia and Required Rates of Return

A. Construction of Risk Premia

For each month, a "market" required rate of return is calculated using each dividend paying stock in the S&P 500 index for which data are available. The DCF model in Equation (2) is applied to each stock and the results weighted by market value of equity to produce the market required return.[7] The return is converted to a risk premium

Exhibit 1. Variable Definitions

k	=	Equity required rate of return.
P_0	=	Average daily price per share.
D_1	=	Expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1 + g)$.[a]
g	=	Average financial analysts' forecast of five-year growth rate in earnings per share (from IBES).
i_{lt}	=	Yield to maturity on long-term U.S. government obligations (source: Federal Reserve Bulletin, constant maturity series).
i_c	=	Yield to maturity on long-term corporate bonds: Moody's average.[b]
rp	=	Equity risk premium calculated as $rp = k - i$.
β	=	beta, calculated from CRSP monthly data over 60 months.

Notes:
[a]See footnote 7 for a discussion of the $(1 + g)$ adjustment.
[b]The average corporate bond yield across bond rating categories as reported by Moody's. See *Moody's Bond Survey* for a brief description and the latest published list of bonds included in the bond rating categories.

[5]Harris [12] provides a discussion of IBES data and its limitations. In more recent years, IBES has begun collecting forecasts for each of the next five years. Since this work was completed, the FAF used here have become available from IBES Inc., now a subsidiary of CitiBank.

[6]While the model calls for expected growth in dividends, no source of data on such projections is readily available. In addition, in the long run, dividend growth is sustainable only via growth in earnings. As long as payout ratios are not expected to change, the two growth rates will be the same.

[7]The construction of D_1 is controversial since dividends are paid quarterly and may be expected to change during the year; whereas, Equation (2), as is typical, is being applied to annual data. Both the quarterly payment of dividends (due to investors' reinvestment income before year's end, see Linke and Zumwalt [15]) and any growth during the year require an upward adjustment of the current annual rate of dividends to construct D_1. If quarterly dividends grow at a constant rate, both factors could be accommodated straightforwardly by applying Equation (2) to quarterly data with a quarterly growth rate and then annualizing the estimated quarterly required return. Unfortunately, with lumpy changes in dividends, the precise nature of the adjustment depends on both an individual company's pattern of growth during the calendar year and an individual company's required return (and hence reinvestment income in the risk class).
In this work, D_1 is calculated as $D_0\ (1 + g)$. The full g adjustment is a crude approximation to adjust for both growth and reinvestment income. For example, if one expected dividends to have been raised, on average, six months ago, a "1/2 g" adjustment would allow for growth, and the remaining "1/2 g" would be justified on the basis of reinvestment income. Any precise accounting for both reinvestment income and growth would require tracking each company's dividend change history and making explicit judgments about the quarter of the next change. Since no organized "market" forecast of such a detailed nature exists, such a procedure is not possible. To get a feel for the magnitudes involved, during the sample period the dividend yield (D_1/P_0) and growth (market value weighted) for the S&P 500 were typically 4% to 6% and 11% to 13%, respectively. As a result, a "full g" adjustment on average increases the required return by 60 to 70 basis points (relative to no g adjustment).

Exhibit 2. Bond Market Yields, Equity Required Return, and Equity Risk Premium,[a] 1982-1991

	Bond Market Yields[b]		Equity Market Required Return[c]	Equity Risk Premium	
Year	(1) U.S. Gov't	(2) Moody's Corporates	(3) S&P 500	U.S. Gov't (3) - (1)	Moody's Corporates (3) - (2)
1982	12.92	14.94	20.08	7.16	5.14
1983	11.34	12.78	17.89	6.55	5.11
1984	12.48	13.49	17.26	4.78	3.77
1985	10.97	12.05	16.32	5.37	4.28
1986	7.85	9.71	15.09	7.24	5.38
1987	8.58	9.84	14.71	6.13	4.86
1988	8.96	10.18	15.37	6.41	5.19
1989	8.46	9.66	15.06	6.60	5.40
1990	8.61	9.77	15.69	7.08	5.92
1991[d]	8.21	9.41	15.61	7.40	6.20
Average[e]	9.84	11.18	16.31	6.47	5.13

Notes:
[a]Values are averages of monthly figures in percent.
[b]Yields to maturity.
[c]Required return on value weighted S&P 500 index using Equation (1).
[d]Figures for 1991 are through May.
[e]Months weighted equally.

over government bonds by subtracting i_{lt}, the yield to maturity on long-term government bonds. A risk premium over corporate bond yields is also constructed by subtracting i_c, the yield on long-term corporate bonds. Exhibit 2 reports the results by year (averages of monthly data).

The results are quite consistent with the patterns reported earlier (i.e., Harris [12]). The estimated risk premia in Exhibit 2 are positive, consistent with equity owners demanding additional rewards over and above returns on debt securities. The average expectational risk premium (1982 to 1991) over government bonds is 6.47%, only slightly higher than the 6.16% average for 1982 to 1984 reported earlier (Harris [12]). Furthermore, Exhibit 2 shows the estimated risk premia change over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities.

For comparison purposes, Exhibit 3 contains historical returns and risk premia. The average expectational risk premium reported in Exhibit 2 falls roughly midway between the arithmetic (7.5%) and geometric (5.7%) long-term differentials between returns on stocks and long-term government bonds. Note, however, that the expectational risk premia appear to change over time. In the following sections, we examine the estimated risk premia to see if they vary cross-sectionally with the risk of individual stocks and over time with financial market conditions.

B. Cross-Sectional Tests

Earlier, Harris [12] conducted crude tests of whether expectational equity risk premia varied with risk proxied by bond ratings and the dispersion of analysts' forecasts and found that required returns increased with higher risk. Here we examine the link between these premia and beta, perhaps the most commonly used measure of risk for equities.[8] In keeping with traditional work in this area, we adopt the methodology introduced by Fama and Macbeth [9] but replace realized returns with expected returns from Equation (2) as the variable to be explained. For this portion of our tests, we restrict our sample to 1982-1987

[8]For other efforts using expectational data in the context of the two-parameter CAPM, see Friend, Westerfield, and Granito [10], Cragg and Malkiel [7], Marston, Crawford, and Harris [19], Marston and Harris [20], and Linke, Kannan, Whitford, and Zumwalt [16]. For a more complete treatment of the subject, see Marston and Harris [20] from which we draw some of these results. Marston and Harris also investigate the role of unsystematic risk and the difference in estimates found when using expected versus realized returns.

Exhibit 3. Average Historical Returns on Bonds, Stocks, Bills, and Inflation in the U.S., 1926-1989

Historical Return Realizations	Geometric	Arithmetic
Common stock	10.3%	12.4%
Long-term government bonds	4.6%	4.9%
Long-term corporate bonds	5.2%	5.5%
Treasury bills	3.6%	3.7%
Inflation rate	3.1%	3.2%

Source: Ibbotson Associates, Inc., *1990 Stocks, Bonds, Bills and Inflation*, 1990 Yearbook.

and in any month include firms that have at least three forecasts of earnings growth to reduce measurement error associated with individual forecasts.[9] This restricted sample still consists of, on average, 399 firms for each of the 72 months (or 28,744 company months).

For a given company in a given month, beta is estimated via the market model (using ordinary least squares) on the prior 60 months of return data taken from CRSP. Beta estimates are updated monthly and are calculated against an equally weighted index of all NYSE securities. For each month, we aggregate firms into 20 portfolios (consisting of approximately 20 securities each). The advantage of grouped data is the reduction in potential measurement error inherent in independent variables at the company level. Portfolios are formed based on a ranking of beta estimated from a prior time period (t = -61 to t = -120). Portfolio expected returns and beta are calculated as the simple averages for the individual securities.

Using these data, we estimate the following model for each of the 72 months:

$$R_p = \alpha_0 + \alpha_1 \beta_p + u_p, \quad p = 1...20, \qquad (3)$$

where:

R_p = Expected return for portfolio p in the given month,

β_p = Portfolio beta, estimated over 60 prior months, and

u_p = A random error term with mean zero.

As a result of estimating regression (3) for each month, 72 estimates of each coefficient (α_0 and α_1) are obtained. Using realized returns as the dependent variable, the traditional approach (e.g., Fama and Macbeth [9]) is to assume that realized returns are a fair game. Given this assumption, the mean of the 72 values of each coefficient is an unbiased estimate of the mean over that same time period if one could have actually used expected returns as the dependent variable. Note that if expected returns are used as the dependent variable the fair-game assumption is not required. Making the additional assumption that the true value of the coefficient is constant over the 72 months, a test of whether the mean coefficient is different from zero is performed using a t-statistic where the denominator is the standard error of the 72 values of the coefficient. This is the technique employed by Fama and Macbeth [9]. If one assumes the CAPM is correct, the coefficient α_1 is an empirical estimate of the market risk premium, which should be positive.

To test the sensitivity of the results, we also repeat our procedures using individual security returns rather than portfolios. To account, at least in part, for differences in precision of coefficient estimates in different months we also report results in which monthly parameter estimates are weighted inversely by the standard error of the coefficient estimate rather than being weighted equally (following Chan, Hamao, and Lakonishok [6]).

Exhibit 4 shows that there is a significant positive link between expectational required returns and beta. For instance, in Panel A, the mean coefficient of 2.78 on beta is significantly different from zero at better than the 0.001 level (t = 35.31), and each of the 72 monthly coefficients going into this average is positive (as shown by that 100% positive figure). Using individual stock returns, the significant positive link between beta and expected return remains, though it is smaller in magnitude than for portfolios.[10] Comparison of Panels A and B shows that the results are not sensitive to the weighting of monthly coefficients.

While the findings in Exhibit 4 suggest a strong positive link between beta and risk premia (a result often not supported when realized returns are used as a proxy for expectations; e.g., see Tinic and West [22]), the results do not support the predictions of a simple CAPM. In particular, the intercept is higher than a proxy for the risk-free rate over the sample period and the coefficient of beta is well below estimates of a market risk premium obtained from either expectational (Exhibit 2) or historical data (Exhibit

[9]Firms for which the standard deviation of individual FAF exceeded 20 in any month were excluded since we suspect some of these involve errors in data entry. This screen eliminated very few companies in any month. The 1982-1987 period was chosen due to the availability of data on betas.

[10]The smaller coefficients on beta using individual stock portfolio returns are likely due in part to the higher measurement error in measuring individual stock versus portfolio betas.

Exhibit 4. Mean Values of Monthly Parameter Estimates for the Relationship Between Required Returns and Beta for Both Portfolios and Individual Securities (Figures in Parentheses are *t* Values and Percent Positive), 1982-1987

Panel A. Equal Weighting[a]

	Intercept	B	Adjusted R^2 [c]	F[c]
Portfolio returns	14.06 (54.02, 100)	2.78 (35.31, 100)	0.503	25.4
Security returns	14.77 (58.10, 100)	1.91 (16.50, 99)	0.080	39.0

Panel B. Weighted by Standard Errors[b]

	Intercept	B	Adjusted R^2 [c]	F[c]
Portfolio returns	13.86 (215.6, 100)	2.67 (35.80, 100)	0.503	25.4
Security returns	14.63 (398.9, 100)	1.92 (47.3, 99)	0.080	39.0

[a]Equally weighted average of monthly parameters estimated using cross-sectional data for each of the 72 months, January 1982 - December 1987.
[b]In obtaining the reported means, estimates of the monthly intercept and slope coefficients are weighted inversely by the standard error of the estimate from the cross-sectional regression for that month.
[c]Values are averages for the 72 monthly regressions.

3).[11] Nonetheless, the results show that the estimated risk premia conform to the general theoretical relationship between risk and required return that is expected when investors are risk-averse.

C. Time Series Tests — Changes in Market Risk Premia

A potential benefit of using ex ante risk premia is the estimation of changes in market risk premia over time. With changes in the economy and financial markets, equity investments may be perceived to change in risk. For instance, investor sentiment about future business conditions likely affects attitudes about the riskiness of equity investments compared to investments in the bond markets. Moreover, since bonds are risky investments themselves, equity risk premia (relative to bonds) could change due to changes in perceived riskiness of bonds, even if equities displayed no shifts in risk. For example, during the high interest rate period of the early 1980s, the high level of interest rate volatility made fixed income investments more risky holdings than they were in a world of relatively stable rates.

Studying changes in risk premia for utility stocks, Brigham, et al [4] conclude that, prior to 1980, utility risk premia increased with the level of interest rates, but that this pattern reversed thereafter, resulting in an inverse correlation between risk premia and interest rates. Studying risk premia for both utilities and the equity market generally, Harris [12] also reports that risk premia appear to change over time. Specifically, he finds that equity risk premia decreased with the level of government interest rates, increased with the increases in the spread between corporate and government bond yields, and increased with increases in the dispersion of analysts' forecasts. Harris' study is, however, restricted to the 36-month period, 1982 to 1984.

Exhibit 5 reports results of analyzing the relationship between equity risk premia, interest rates, and yield spreads between corporate and government bonds. Following Harris [12], these bond yield spreads are used as a time series proxy for equity risk. As the perceived riskiness of corporate activity increases, the difference between yields on corporate bonds and government bonds should increase. One would expect the sources of increased riskiness to corporate bonds to also increase risks to shareholders. All regressions in Exhibit 5 are corrected for serial correlation.[12]

[11]Estimation difficulties confound precise interpretation of the intercept as the risk-free rate and the coefficient on beta as the market risk premium (see Miller and Scholes [21], and Black, Jensen, and Scholes [2]). The higher than expected intercept and lower than expected slope coefficient on beta are consistent with the prior studies of Black, Jensen, and Scholes [2], and Fama and MacBeth [9] using historical returns. Such results are consistent with Black's [1] zero beta model, although alternative explanations for these findings exist as well (as noted by Black, Jensen, and Scholes [2]).

[12]Ordinary least squares regressions showed severe positive autocorrelation in many cases, with Durbin Watson statistics typically below one. Estimation used the Prais-Winsten method. See Johnston [14, pp. 321-325].

Exhibit 5. Changes in Equity Risk Premia Over Time — Entries are Coefficient (*t*-value); Dependent Variable is Equity Risk Premium

Time period	Intercept	i_{lt}	$i_c - i_{lt}$	R^2
A. May 1991-19~~9~~2	0.131	-0.651		0.53
	(19.82)	(-11.16)		
8	0.092	-0.363	0.666	0.54
	(14.26)	(-6.74)	(5.48)	
B. 1982-1984	0.140	-0.637		0.43
	(8.15)	(-5.00)		
	0.064	-0.203	1.549	0.60
	(3.25)	(-1.63)	(4.84)	
C. 1985-1987	0.131	-0.739		0.74
	(7.73)	(-9.67)		
	0.110	-0.561	0.317	0.77
	(12.53)	(-7.30)	(1.87)	
D. 1988-1991	0.136	-0.793		0.68
	(16.23)	(-8.29)		
	0.130	-0.738	0.098	0.68
	(8.71)	(-4.96)	(0.40)	

Note: All variables are defined in Exhibit 1. Regressions were estimated using monthly data and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression, variables are expressed in decimal form, e.g., 14% = 0.14.

For the entire sample period, Panel A shows that risk premia are negatively related to the level of interest rates — as proxied by yields on government bonds, i_{lt}. This negative relationship is also true for each of the subperiods displayed in Panels B through D. Such a negative relationship may result from increases in the perceived riskiness of investment in government debt at high levels of interest rates. A direct measure of uncertainty about investments in government bonds would be necessary to test this hypothesis directly.

For the entire 1982 to 1991 period, the addition of the yield spread risk proxy to the regressions dramatically lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations 1 and 2 of Panel A. Furthermore, the coefficient of the yield spread (0.666) is itself significantly positive. This pattern suggests that a reduction in the risk differential between investment in government bonds and in corporate activity is translated into a lower equity market risk premium. Further examination of Panels B through D, however, suggests that the yield spread variable is much more important in explaining changes in equity risk premia in the early portion of the 1980s than in the 1988 to 1991 period.

In summary, market equity risk premia change over time and appear inversely related to the level of government interest rates but positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds.

IV. Conclusions

Shareholder required rates of return and risk premia are based on theories about investors' expectations for the future. In practice, however, risk premia are often estimated using averages of historical returns. This paper applies an alternate approach to estimating risk premia that employs publicly available expectational data. At least for the decade studied (1982 to 1991), the resultant average market equity risk premium over government bonds is comparable in magnitude to long-term differences (1926 to 1989) in historical returns between stocks and bonds. There is strong evidence, however, that market risk premia change over time and, as a result, use of a constant historical average risk premium is not likely to mirror changes in investor return requirements. The results also show that the expectational risk premia vary cross-sectionally with the relative risk (beta) of individual stocks.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (e.g., portfolios of utility stocks) appropriate for a particular decision as well as analyze changes in equity return requirements over time.

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The relationship between systematic risk and expected return can also be expressed mathematically. The CAPM describes the cost of equity for any company's stock as equal to the riskless rate plus an amount proportionate to the systematic risk an investor assumes.

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

where:

k_s = the cost of equity 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.

Since the CAPM has only three variables—the expected return on the riskless asset, the beta of the stock, and the expected equity risk premium—it is one of the easiest models to implement in practice. However, an estimate of each of the above three variables must be formed. Like all components of the cost of capital, these variables should be measured on a forward-looking basis. Chapters 5 and 6 are devoted to estimating the equity risk premium and beta, respectively. Factors to consider in estimating the riskless rate are covered below.

Risk-Free Rate

In general, most valuators can agree that the risk-free rate is a forward looking rate that factors in long-term expectations on growth and inflation. The CAPM implicitly assumes the presence of a single riskless asset—that is, an asset perceived by all investors as having no risk. The ability of the U.S. government to create money to fulfill its debt obligations under virtually any scenario makes U.S. Treasury securities practically default-free. While interest rate changes cause government obligations to fluctuate in price, investors face essentially no default risk as to either coupon payment or return of principal. Asset values can vary significantly depending upon the type of risk-free interest rate selected and cash distribution characteristics of the subject asset being valued, the time horizon, and how a valuation practitioner applies this rate into his or her model.

Type of Interest Rate

A common choice for the nominal riskless rate is the yield on a U.S. Treasury security. Should the yield on a Treasury bond or a Treasury STRIPS be used to represent the riskless rate? In most cases, the yield on a Treasury coupon bond is most appropriate. If the asset being measured spins off cash periodically, the Treasury bond most closely replicates this characteristic. On the other hand, if the asset being measured provides a single payoff at the end of a specified term, the yield on a Treasury STRIPS would be more appropriate.

Time Horizon

The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate, since the company will continue to exist beyond those five years.

A different vantage point of the time horizon is that the risk-free rate should best match the distribution of the periodic cash flows of the asset being valued, in which case applying a yield curve may be more appropriate.

Table 4-1: Current Yields or Expected Riskless Rates

Yield (Riskless Rate)	(%)*
Long-Term (20-year) U.S. Treasury Coupon Bond Yield	2.41
Long-Term (10-year) U.S. Treasury Coupon Bond Yield	1.78
Intermediate-Term (5-year) U.S. Treasury Coupon Note Yield	0.46
Short-term (30-day) U.S. Treasury Bill Yield	0.02

Data as of December 31, 2012.
*Maturities are approximate.

It is also important to note that in February 1977, the Treasury began to issue 30-year Treasury securities. Prior to this date, the longest-term Treasury security was 20 years, which was the standard Ibbotson used for its data series. To remain consistent with Ibbotson's historical data series, the *Ibbotson® Stocks, Bonds, Bills, and Inflation® Classic Yearbook* continued to base the yield

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these two years excluded. It is clear from this example that a long time period is required to accurately estimate the equity risk premium. The shorter 30-year period places too much emphasis on the poor market performances of 1973–1974. In fact, the equity risk premium recovers significantly in more recent periods once the years 1973 and 1974 are truncated from the analysis, as seen in the rolling 20-year and 10-year Ibbotson data.

Some analysts employ a rolling average approach. For example, the analyst arbitrarily assumes a given time frame over which the equity risk premium should be calculated, say 30 years, and calculates a 30-year equity risk premium for all time periods from 1926 to the present. There is a premium for 1926–1955, 1927–1956, and so on to the present. The successive premiums are averaged to arrive at the eventual equity risk premium. This approach is highly suspect because it overweighs the middle years. In the example, the year 1926 appears in one 30-year average, 1927 in two 30-year averages, etc. Yet, the most current (and relevant) time period only appears once. The middle periods are given an inordinate amount of weight using this approach. The other fallacy of the approach is that it assumes that a 30-year period is an appropriate historical window over which to estimate the equity risk premium. This assumption is highly arbitrary.

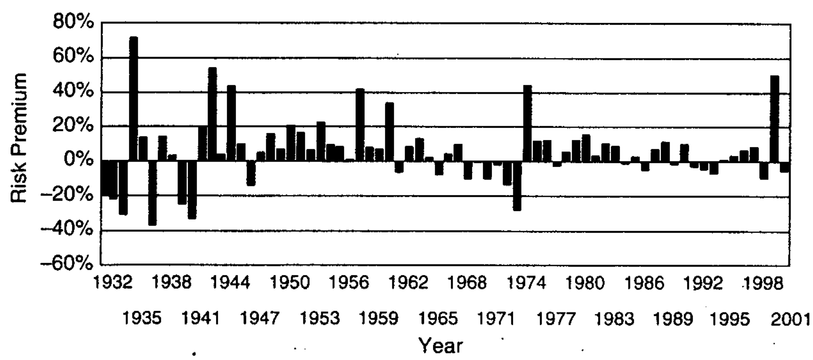
While forward-looking risk premiums based on expected returns are preferable, historical return studies over long periods still provide a useful guide for the future. This is because over long periods, investors' expectations are eventually revised to match historical realizations, as market prices adjust to match anticipated and actual investment results. Otherwise, investors would never commit investment capital. In the long run, the difference between expected and realized risk premiums will decline because short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect. Second, the investors' current expectations concerning the amount by which the return on equity will exceed the bond yield will be strongly influenced by historical differences in returns to bond and stock investors. For these reasons, we can estimate investors' current expected returns from an equity investment from knowledge of current bond yields and past differences between returns on stocks and bonds.

Computational Issues: Arithmetic vs Geometric Average

The second problem in relying on historical return results is the method of averaging historical returns, that is, whether to use the ordinary average (arithmetic mean) or the geometric mean return. Because valuation is forward-looking, the appropriate average is the one that most accurately approximates the expected future rate of return. The best estimate of expected returns over a given future holding period is the arithmetic average. Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital. There is no theoretical or empirical justification for the use of geometric mean rates of returns as a measure of the appropriate discount rate in computing the cost of capital or in computing present values. There is no dispute in academic circles as to whether the arithmetic or geometric average should be used for purposes of computing the cost of capital. The arithmetic mean should always be used in calculating the present value of a cash flow stream. Appendix A contains a comprehensive discussion of this issue, including the underlying theory, empirical evidence, and formal demonstrations.

Drawn from an actual rate case, the implementation of the historical Risk Premium approach is illustrated in Example 4-1 for the electric utility industry. Over the long term, realized utility equity risk premiums were 5.6% above Treasury bond yields for electric utilities.

FIGURE 4-2
EQUITY RISK PREMIUM
Electric Utilities 1931–2002



EXAMPLE 4-1

As a proxy for the risk premium applicable to the electric utility industry, a historical risk premium for the electric utility industry is estimated with an annual time series analysis applied to the industry as a whole, using *Moody's Electric Utility Index* as an industry proxy. The analysis is depicted in Figure 4-2. The risk premium is estimated by computing the actual return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. Dividend yields and stock prices on the index are obtained from *Moody's*

(continued next page)

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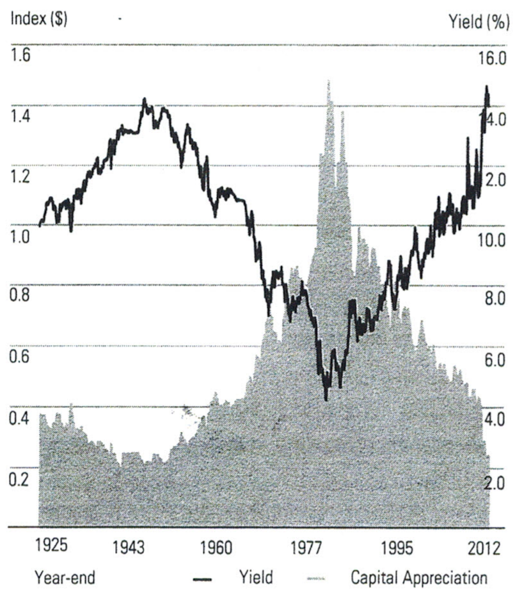
around since the 1980s, however. Graph 5-1 illustrates the yields on the long-term government bond series compared to an index of the long-term government bond capital appreciation. In general, as yields rose, the capital appreciation index fell, and vice versa. Had an investor held the long-term bond to maturity, he would have realized the yield on the bond as the total return. However, in a constant maturity portfolio, such as those used to measure bond returns in this publication, bonds are sold before maturity (at a capital loss if the market yield has risen since the time of purchase). This negative return is associated with the risk of unanticipated yield changes.

Graph 5-1: Long-term Government Bond Yields versus Capital Appreciation Index



Data from 1925–2012.

For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-2 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

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securities to the point at which new purchases would earn only the old cost of capital on their investments. The only beneficiaries would be those who happened to own the stock at the time the policy change was announced or anticipated.

12.5 M/B Ratios in the Regulatory Process

It is sometimes argued that because current M/B ratios are in excess of 1.0, this indicates that companies are expected by investors to be able to earn more than their cost of capital, and that the regulating authority should lower the authorized return on equity, so that the stock price will decline to book value. It is therefore plausible, under this argument, that stock prices drop from the current M/B value to the desired M/B ratio range of 1.0 times book.

There are several reasons why this view of the role of M/B ratios in regulation should be avoided.

(1) The inference that M/B ratios are relevant and that regulators should set an ROE so as to produce an M/B of 1.0 is misguided. The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce an M/B of 1.0 presumes that investors are irrational. They commit capital to a utility with an M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation. For example, assume a utility company with an M/B ratio of 1.5. If investors expect the regulator to authorize a return on book value equal to the DCF cost of equity, the utility stock price would decline to book value, inflicting a capital loss of some 30%. The notion that investors are willing to pay a price of 1.5 times book value only to see the market value of their investment drop by 30% is irrational.

(2) The condition that the M/B will gravitate toward 1.0 if regulators set the allowed return equal to capital costs will be met only if the actual return expected to be earned by investors is at least equal to the cost of capital on a consistent long-term basis and absent inflation. The cost of capital of a company refers to the expected long-run earnings level of other firms with similar risk. If investors expect a utility to earn an ROE equal to its cost of equity in each period, then its M/B ratio would be approximately 1.0 or higher with the proper allowance for flotation cost.

(3) A company's achieved earnings in any given year are likely to exceed or be less than their long-run average. Depressed or inflated M/B ratios are to a considerable degree a function of forces outside the control of regulators, such as the general state of the economy, or general economic or financial circumstances that may affect the yields on securities of unregulated as well

as regulated enterprises. The achievement of a 1.0 M/B ratio is appropriate, but only in a long-run sense. For utilities to exhibit a long-run M/B ratio of 1.0, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.0 to compensate for the periods during which the M/B ratio is less than its long-run average under less favorable economic and capital market conditions.

Historically, the M/B ratio for utilities has fluctuated above and below 1.0. It has been consistently above 1.0 from the 1980s to the mid 2000s. This indicates that earnings below capital costs and M/B ratios below 1.0 during less favorable economic and capital market conditions must necessarily be accompanied with earnings in excess of capital costs and M/B ratios above 1.00 during more favorable economic and capital market conditions.

M/B ratios are determined by the marketplace, and utilities cannot be expected to compete for and attract capital in an environment where industrials are commanding M/B ratios well in excess of 1.0 while regulation reduces their M/B ratios toward 1.0. Moreover, if regulators were to currently set rates so as to produce an M/B ratio of 1.0, not only would the long-run target M/B ratio of 1.0 be violated, but more importantly, the inevitable consequence would be to inflict severe capital losses on shareholders. Investors have not committed capital to utilities with the expectation of incurring capital losses from a misguided regulatory process.

(4) Rate of return regulation is fundamentally a surrogate for competition. The fundamental goal of regulation should be to set the expected economic profit for a public utility equal to the level of profits expected to be earned by firms of comparable risk, in short, to emulate the competitive result. For unregulated firms, the natural forces of competition will ensure that in the long run, the ratio of the market value of these firms' securities equals the replacement cost of their assets. Competitive industrials of comparable risk to utilities have consistently been able to maintain the real value of their assets in excess of book value, consistent with the notion that, under competition, the Q-ratio will tend to 1.00 and not the M/B ratio. This suggests that a fair and reasonable price for a public utility's common stock is one that produces equality between the market price of its common equity and the replacement cost of its physical assets. The latter circumstance will not necessarily occur when the M/B ratio is 1.0. As the previous section demonstrated, only when the book value of the firm's common equity equals the value of the firm's equity at replacement assets will equality hold.

In an inflationary period, the replacement cost of a firm's assets may increase more rapidly than its book equity. To avoid the resulting economic confiscation of shareholders' investment in real terms, the allowed rate of return should produce an M/B ratio which provides a Q-ratio of 1 or a Q-ratio equal to that of comparable firms. It is quite plausible and likely that M/B ratios will exceed one if inflation increases the replacement cost of a firm's assets at a faster pace than historical cost (book equity). Perhaps this explains in part why utility M/B ratios have remained well above 1.0 over the past two decades. Are we to conclude that regulators have been systematically misguided all across the United States for all these years by awarding overgenerous returns, or are we to conclude that M/B ratios are largely immaterial in the context of ratemaking? The latter is more likely.

Historically, it has been highly unusual for utility stock prices to equal book value. Stock prices above book value are common for utility stocks, and indeed for all of the major market indexes. It is obvious that regulators, through their rate case decisions, and investors do not subscribe to the notion that utilities that have market prices above book value are over-earning. Otherwise, regulators would not grant rate increases for any utility whose stock price was above book value, and investors would never bid up the price of stock above book value. It is very difficult to accept the notion that, in a free-market economy with rampant competition, the vast majority of all publicly traded-stocks are earning well in excess of their cost of capital.

In short, economic principles do not support the notion that the market value of utility shares should necessarily equal book value. A basic economic principle holds that, in the long run, market value should equal asset replacement cost in a given industry. In the presence of inflation and absent significant technological advances, replacement cost exceeds the original cost book value of assets. Consequently, it is quite reasonable for the market value of utility shares to exceed their book value and there is no reason to conclude that market value should equal book value when one recognizes that regulation is intended to emulate competition.

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This document is an abbreviated "Preview Version" of the key year-end (December 31, 2016) valuation data available in the hardcover *2017 Valuation Handbook – U.S. Guide to Cost of Capital*.

This document is made available to purchasers who have pre-ordered the *2017 Valuation Handbook – U.S. Guide to Cost of Capital*. The purpose of this document is to provide key year-end 2016 valuation data to pre-order purchasers while the hardcover *2017 Valuation Handbook – U.S. Guide to Cost of Capital* is being printed.

The *2017 Valuation Handbook – U.S. Guide to Cost of Capital* will ship in mid-March 2017, and will include two sets of valuation data:

- Data previously available in the *SBBI® Valuation Yearbook*; and
- Data available in the Duff & Phelps *Risk Premium Report*.

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CRSP Deciles Size Premia Study: Key Variables

As of December 31, 2016

Yield (Risk-free Rate)

Long-term (20-year) U.S. Treasury Coupon Bond Yield	2.72%

Equity Risk Premium[1]

Long-horizon expected equity risk premium (historical) : large company stock total returns minus long-term government bond income returns	6.94
Long-horizon expected equity risk premium (supply-side) : historical equity risk premium minus price-to-earnings ratio calculated using three-year average earnings	5.97
Duff & Phelps recommended equity risk premium (conditional) : The Duff & Phelps recommended ERP was developed in relation to (and should be used in conjunction with) a 3.5% "normalized" risk-free rate.[2]	5.50

CRSP Deciles Size Premium[3]

Decile	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
Mid-Cap 3-5	$2,392.689	–	$10,711.194	1.02%
Low-Cap 6-8	569.279	–	2,390.899	1.75
Micro-Cap 9-10	2.516	–	567.843	3.67
Breakdown of CRSP Deciles 1-10				
1-Largest	$24,361.659	–	$609,163.498	-0.35%
2	10,784.101	–	24,233.747	0.61
3	5,683.991	–	10,711.194	0.89
4	3,520.566	–	5,676.716	0.98
5	2,392.689	–	3,512.913	1.51
6	1,571.193	–	2,390.899	1.66
7	1,033.341	–	1,569.984	1.72
8	569.279	–	1,030.426	2.08
9	263.715	–	567.843	2.68
10-Smallest	2.516	–	262.891	5.59
Breakdown of CRSP 10th Decile				
10a	$127.296	–	$262.891	4.09%
10w	190.553	–	262.891	3.10
10x	127.296	–	190.383	5.33
10b	$2.516	–	$127.279	8.64%
10y	73.561	–	127.279	7.21
10z	2.516	–	73.504	11.63

[1] See Chapter 3 for complete methodology.

[2] See Exhibit 3.19.

[3] See Chapter 7 for complete methodology.

Note: Examples on how these variables can be used are found in Chapter 8.

Sources of underlying data: 1.) CRSP U.S. Stock Database and CRSP U.S. Indices Database © 2017 Center for Research in Security Prices (CRSP®), University of Chicago Booth School of Business. 2.) Morningstar *Direct* database. Used with permission. All rights reserved. Calculations performed by Duff & Phelps, LLC.

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Short communication

Utility stocks and the size effect—revisited

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Abstract

Wong concluded there is weak empirical support that firm size is a missing factor from the capital asset pricing model for industrial stocks but not for utility stocks. Her weak results, however, do not rule out the possibility of a small firm effect for utilities. The issue she addressed has important financial implications in regulated proceedings that set rates of return for utilities. New studies based on different size water utilities are presented that do support a small firm effect in the utility industry.

Keywords: Utility stocks; Beta risk; Firm size

Annie Wong concludes there is some weak evidence that firm size is a missing factor from the capital asset pricing model ("CAPM") for industrial stocks but not for utility stocks (Wong, 1993, p. 98). This "firm size effect" is an observation that small firms tend to earn higher returns than larger firms after controlling for differences in estimates of beta risk in the CAPM. Wong notes that if the size effect exists, it has important implications and should be considered by regulators when they determine fair rates of return for public utilities. This paper re-examines the basis for her conclusions and presents new information that indicates there is a small firm effect in the utility sector.

1. Reconsideration of the evidence provided by Wong

Wong relies on Barry and Brown (1984) and Brauer (1986) to suggest the small firm effect may be explained by differences in information available to investors of small and large firms.

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She states that requirements to file reports and information generated during regulatory proceedings indicate the same amount of information is available for large and small utilities and thus, if the differential information hypothesis explains the small firm effect, then the uniformity of information available among utility firms would suggest the size effect should not be observed in the utility industry. But contrary to the facts she assumes, there are differences in information available for large and small utilities. More parties participate in proceedings for large utilities and thus generate more information. Also, in some jurisdictions smaller utilities are not required to file all of the information that is required of larger firms. Thus, if the small firm effect is explained by differential information, contrary to Wong's hypothesis, differences in available information suggests there is a small firm effect in the utility industry. Wong did not discuss other potential explanations of the small firm effect for utilities.[2]

Wong's empirical results are not strong enough to conclude that beta risks of utilities are unrelated to size. In the period 1963–1967, when monthly data were used to estimate betas, her estimates of utility betas as well as industrial betas increased as the size of the firms decreased, but she did not find the same inverse relationship between size and beta risk for utilities in other periods. Being unable to demonstrate a relationship between size and beta in other periods may be the result of Wong using monthly, weekly and daily data to make those beta estimates. Roll (1980) concluded trading infrequency seems to be a powerful cause of bias in beta risk estimates when time intervals of a month or less are used to estimate betas for small stocks. When a small stock is thinly traded, its stock price does not reflect the movement of the market, which drives down the apparent covariance with the market and creates an artificially low beta estimate.

Ibbotson Associates (2002) found that when annual data are used to estimate betas, beta estimates for the smaller firms increase more than beta estimates for larger firms. Table 1 compares Value Line (2000) beta estimates for three relatively small water utilities that are made with weekly data and an adjusted beta estimated with pooled annual data for the utilities for the 5-year period ending in December 2000. In making the latter estimate, it is assumed that the underlying beta for each of water utilities is the same. The *t*-statistics for the unadjusted beta

Table 1
Beta estimates reported by Value Line and estimated with pooled annual returns for relatively small water utilities

	Value Line[a]	Estimated with annual data[b]
Connecticut Water Service	0.45	
Middlesex Water	0.45	
SJW Corporation	0.50	
Average	0.47	0.78
t-statistic		2.72[c,d]

[a] As reported in Value Line (2000). Betas estimated with 5 years of weekly data.

[b] Estimated with pooled annual return premiums for the 5-year period ending December 2000. Proxy market returns are total returns for the S&P 500 index. Dummy variable in 1999 to reflect the proposed acquisition of SJW Corporation included in analysis.

[c] Significant at the 95% level.

[d] The *t*-statistic for the null hypothesis that the true beta is 0.18 (the derived unadjusted Value Line beta) when the estimated betas is 0.65 (the unadjusted estimated beta) is 1.97. It is significant at the 95% level.

estimate is reported in parentheses. As was found by Ibbotson Associates (2002) for stocks in general, when annual data are used to estimate betas for small utility stocks, the beta estimate increases.

Wong used the Fama and MacBeth (1973) approach to estimate how well firm size and beta explain future returns in four periods. She reports weak empirical results for both the industrial and utility sectors. In every one of the statistical results reported for utilities, the coefficient for the size effect has a negative sign as would be expected if there is a size effect in the utility industry but only one of the results was found to be statistically significant at the 5% level. With the industrial sector, though she found two cases to have a significant size effect, a negative sign for the size coefficient occurred only 75% of the time. What is puzzling is that with these weak results, Wong concludes the analysis provides support for the small firm effect for the industrial industry but no support for a small firm effect for the utility industry.

2. New evidence on risk premiums required by small utilities

Two other studies support a conclusion that small utilities are more risky than larger ones. A study made by Staff of the Water Utilities Branch of the California Public Utilities Commission Advisory and Compliance Division (CPUC Staff, 1991) used proxies for beta risk and determined small water utilities were more risky than larger water utilities. Part of the difficulty with examining the question of relative risk of utilities is that the very small utilities are not publicly-traded. This CPUC Staff study addressed that concern by computing proxies for beta risk estimated with accounting data for the period 1981–1991 for 58 water utilities. Based on that analysis, CPUC Staff concluded that smaller water utilities were more risky and required higher equity returns than larger water utilities. Following 8 days of hearings and testimony by 21 witnesses regarding this study, it was adopted by the California Public Utilities Commission in CPUC Decision 92-03-093, dated March 31, 1992.

Table 2 provides the results of another study of differences in required returns estimated from discounted cash flow ("DCF") model estimates of the costs of equity for water utilities of different sizes. The study compares average estimates of equity costs for two smaller water utilities, Dominguez Water Company and SJW Corporation, with equity cost estimates for two larger companies, California Water Service and American States Water, for the period 1987–1997. All four utilities operated primarily in the same regulatory jurisdiction during that period. Estimates of future growth are required to make DCF estimates. Gordon, Gordon, and Gould (1989) found that a consensus of analysts' forecasts of earnings per share for the next 5 years provides a more accurate estimate of growth required in the DCF model than three different historical measures of growth. Unfortunately, such analysts' forecasts are not generally available for small utilities and thus this study assumes, as was assumed by staff at the regulatory commission, that investors relied upon past measures of growth to forecast the future. The results in Table 2 show that the smaller water utilities had a cost of equity that, on average, was 99 basis points higher than the average cost of equity for the larger water utilities. This result is statistically significant at the 90% level. In terms of the issues being addressed by Wong, the 99 basis points could be the result of differences in beta risk, the small firm effect or some combination of the two.

Table 2
Small firm equity cost differential: case study based on a comparison of DCF equity cost estimates for larger and smaller California water utilities (1987–1997)

	Larger water utilities[a]			Smaller water utilities[b]			Smaller utilities minus larger utilities
	D_0/P_0 (%)	Estimated growth (%)[c]	Equity cost estimate (%)[d]	D_0/P_0 (%)	Estimated growth (%)[c]	Equity cost estimate (%)[d]	
1987	6.60	7.17	14.24	5.38	10.06	15.98	1.74
1988	6.75	6.30	13.48	5.81	9.08	15.42	1.94
1989	7.10	6.30	13.84	6.47	7.00	13.93	0.09
1990	7.24	6.19	13.87	6.96	7.51	14.99	1.11
1991	6.94	6.29	13.67	6.64	6.24	13.30	−0.36
1992	6.18	5.96	12.50	6.50	6.71	13.65	1.14
1993	5.32	5.68	11.30	5.49	6.31	12.15	0.85
1994	6.03	4.40	10.70	5.80	4.86	10.94	0.25
1995	6.44	3.86	10.55	6.44	4.88	11.64	1.09
1996	5.60	4.06	9.88	5.77	5.58	11.67	1.79
1997	4.93	3.31	8.40	4.52	4.89	9.64	1.23
Averarage difference							0.99
t-statistic							1.405[e]

Limited to period for which Dominguez Water Company data were available. 1998 excluded due to pending buyout.

[a] American States Water and California Water Service.

[b] Dominguez Water Company and SJW Corporation.

[c] Average of 5- and 10-year dividends per share growth, 10-year earnings per share growth and estimates of sustainable growth from internal and external sources for the most recent 10-year period when data are available (1991–1997), otherwise most recent 5-year period (1987–1990).

[d] DCF equity cost as computed by California PUC staff: $k = (D_0/P_0) \times (1 + g) + g$.

[e] Significant at the 90% level.

3. Concluding remarks

Wong's concluding remarks should be re-examined and placed in perspective. She noted that industrial betas tend to decrease with increases in firm size but the same relationship is not found in every period for utilities. Had longer time intervals been used to estimated betas, as was done in Table 1, she may have found the same inverse relationship between size and beta risk for utilities in other periods. She also concludes "there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not the utility stocks" (Wong, 1993, p. 98), but the weak evidence provides little support for a small firm effect existing or not existing in either the industrial or utility sector. Two other studies discussed here support a conclusion that smaller water utility stocks are more risky than larger ones. To the extent that water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones.

Notes

1. Vice President.
2. The small firm effect could also be a proxy for numerous other omitted risk differences between large and small utilities. An obvious candidate is differentials in access to financial markets created by size. Some very small utilities are unable to borrow money without backing of the owner. Other small utilities are limited to private placements of debt and have no access to the more liquid financial markets available to larger utilities.

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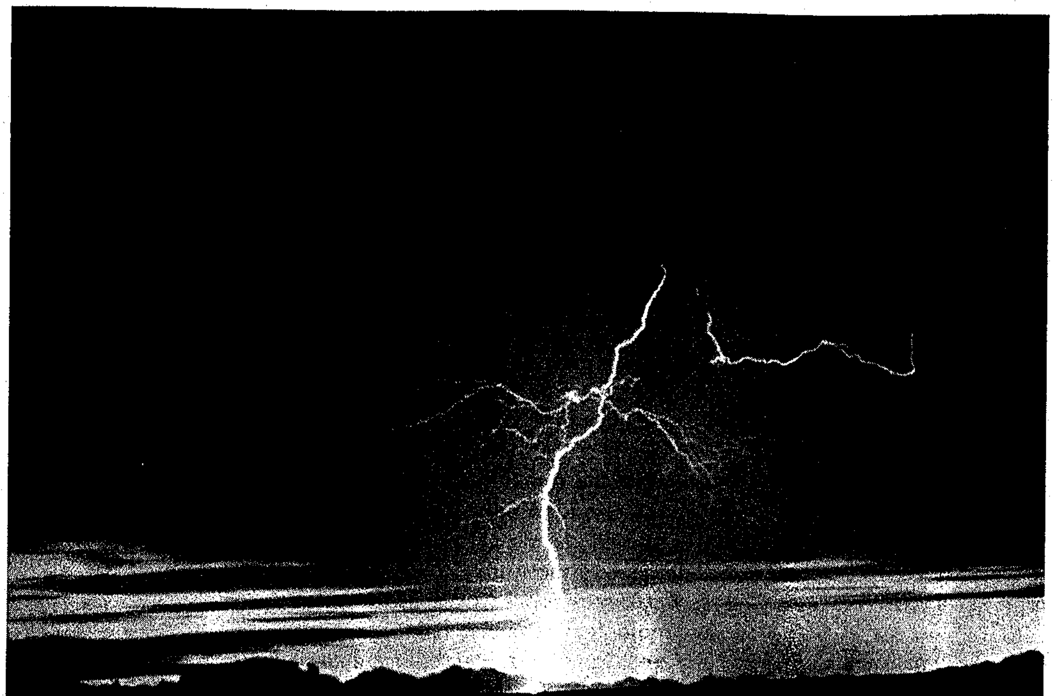

Downgrades Dominate U.S. Utility Ratings in First Half

RATINGSDIRECT SEARCH

Downgrades GO>

Downside rating actions continued to overshadow upward rating activity in the U.S. utility industry (electric, gas, pipeline, and water companies) in this year's energetic first half. Although the negative trend mirrored that of the first six months of 2000, the actual number of rating changes has picked up a bit. There were 45 rating changes (28 downgrades, 17 upgrades) among holding companies and operating subsidiaries, several outlook revisions to negative, and a material increase in negative CreditWatch listings during the first half of 2001. In contrast, there were 34 rating changes (24 downgrades, 10 upgrades) for the same period in 2000 and less than a dozen outlook revisions and CreditWatch placements, most of which were negative.

The increase in rating activity during the first half of 2001 can be traced to the California energy and liquidity crisis that led to several downgrades on PG&E Corp., Edison International, and their affiliates. Other western utilities also saw their credit ratings lowered due to the significant cost increases being experienced throughout the western U.S. energy market. In addition, the declining credit picture continues to be influenced by mergers and acquisitions, capital and corporate restructuring efforts, erosion of bondholder protection parameters, investments outside the traditional regulated utility business and, with respect to California's two largest utilities, defaults. These trends, in turn, reflect companies' strategies to deal with an increasingly competitive market, while also seeking to increase shareholder value in this more uncertain environment.

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UPDATE ON CALIFORNIA CRISIS

Pacific Gas & Electric Co. (PG&E), a PG&E Corp. subsidiary, and Southern California Edison Co. (SoCalEd) began to default on their financial obligations in mid-January, at which time the corporate credit ratings were dropped to 'D'. On April 6, PG&E filed for Chapter 11 bankruptcy protection, stating that its return to financial solvency would be better served in bankruptcy court. Indeed, since last summer, the company and its investors have experienced only frustration—first with respect to stemming the drain of its financial resources by the malfunctioning wholesale power market before these resources finally ran dry, and then with its attempts to recover these resources.

For SoCalEd's creditors, the picture is not much brighter. PG&E's April 6 bankruptcy filing led California Governor Gray Davis to direct his aides to hammer out an agreement with SoCalEd to avert a bankruptcy filing by that utility. The result was the April 10 announcement of a memorandum of understanding (MOU) between SoCalEd and the state that, if implemented, will provide SoCalEd with a partial recovery of the amounts by which purchased-power expenses exceeded revenues.

The implementation of the utility's MOU objectives requires the parties to begin and complete extensive negotiations on a host of issues. Definitive contracts must be negotiated and legislative and regulatory action taken. The rehabilitation of SoCalEd to a financially viable company hinges on actions that must be taken by several parties that are not signatories to the MOU. They include the FERC, the California Independent System Operator, the state legislature, and the California Public Utility Commission (CPUC). Although it is in the public interest for each of the nonsignatory parties to advance the MOU's objectives and restore SoCalEd to solvency, the nonsignatories to the MOU are not bound to take the actions specified to implement the MOU's provisions.

There are many hoops to jump through, and, to date, there has been little progress. In fact, legislators have not focused on devising legislation to implement the MOU. Rather, they have focused on devising alternatives to the MOU.

Given the legislative intransigence, the CPUC did not act in mid-June as contemplated by the MOU. The bleak outlook for the MOU translates into dim prospects for SoCalEd's ability to make its creditors whole and may increase the likelihood of either voluntary or involuntary bankruptcy filing of SoCalEd.

EXPECTATIONS FOR INCREASED DOWNWARD PRESSURE

In just 12 months, the number of companies rated 'A' and above has decreased, while the number of firms rated 'BBB' and below has increased. In this regard, about 40% of the industry now carries a 'BBB' category rating, and 6% is rated below investment grade—compared with 34% and 5%, respectively, on June 30, 2000. In addition, 55% of the industry carry ratings of 'A' and above, compared with 60% one year earlier. Notwithstanding this large number of rating downgrades and ongoing negative pressures on utility creditworthiness, the industry remains solidly investment grade. This is in line with the large percentage of utilities having average or above average business profiles.

Over the long term, Standard & Poor's expects that most companies providing electricity and gas will continue to maintain financial profiles that warrant, at a minimum, investment-grade ratings. However, as the vertically integrated industry continues to split into its component parts of generation, transmission, and distribution, ratings will become more broadly dispersed. The recent trend toward corporate and capital restructuring is beginning to focus on the value and strategic advantages of IPOs and spin-offs. These newly formed entities will achieve ratings based on their financial performance and business risk, while the operations of the original company will be judged separately. Also, utilities that merge with other companies and invest outside the traditional regulated businesses will be rated on the basis of the qualitative and quantitative fundamentals of their consolidated entities. Prospective rating revisions will likely reflect the pace of deregulation among the

Chart 1
Rating Actions Through June 30

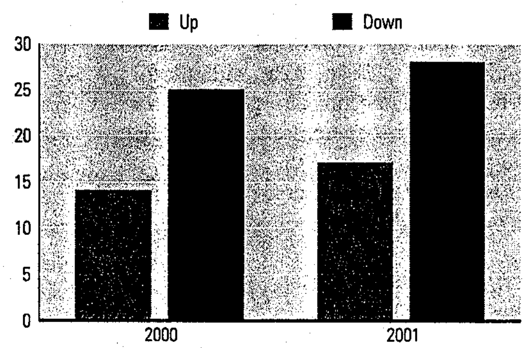
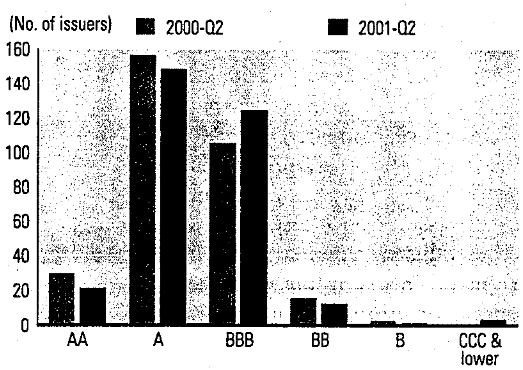


Chart 2
Second-Quarter Rating Distributions, 2000-2001



states (and the effect of the California deregulation debacle), the extent to which unregulated operations increase business risk, as well as the degree of structural or regulatory insulation. Without posting stronger earnings and cash flow measures to compensate for riskier business profiles, ratings could deteriorate.

Financing Up...Leverage Rising, Cash Flow Eroding

Financing activity has risen dramatically in the past 12 months. The amount of debt and preferred stock issued during the first half of this year exceeded the $48 billion mark, compared with about $25 billion issued during the first six months of 2000. The increase in debt financing can be traced to depressed stock prices; a focus on shareholder value; somewhat lower interest rates; accelerating capital expenditures that are primarily related to improvements to existing transmission, distribution, and generation facilities; and investments in nonutility ventures.

The higher level of financing and incremental debt burden will likely drive down key financial parameters, which have been eroding in recent years. Total debt as a percentage of capital has risen to substantial levels and as of Dec. 31, 2000 (the latest period in which comparable data is available) stood at a liberal 60%, compared with 53% five years earlier. Much of the increase is attributable to debt raised at the parent or intermediate holding company level to fund unregulated operations. In addition, continuing disaggregation of the vertically integrated industry has contributed to the financial deterioration. Transmission and distribution firms face limited business risk and can therefore post weaker financial measures to sustain strong ratings. On the other hand, generators are very risky and typically finance mostly with debt. The increase in debt leverage has resulted in a steady decline in the funds from operations (FFO) to total debt and FFO interest coverage ratios. In this regard, FFO to total debt fell to 17% in 2000 from 21.8% in 1997, and FFO interest coverage slipped to 2.8 times (x) in 2000 from 3.92x in 1997.

Looking Ahead

At present, 58% of all utility rating outlooks are stable. However, the dynamic forces that are propelling the demise of the monopolistic, integrated, and heavily regulated utility structure are beginning to affect this stability. This is evident in the exceptionally high 18% of utilities carrying negative outlooks. Negative rating pressures result mostly from weak competitive positioning and a proliferation of growth strategies involving investments in relatively high-risk nonregulated activities, such as power generation, including debt-financed acquisitions of electric generating plants, energy trading and marketing, and/or oil and gas exploration. Of the remaining companies, a staggering 21% are on CreditWatch, a full 58% of which are with negative implications, 28% positive, and 14% developing. The CreditWatch listings are attributable principally to industry consolidation, where companies of different creditworthiness have announced mergers or the mergers are largely debt financed. Given the huge number of companies on CreditWatch, Standard & Poor's expects frequent rating changes to continue as mergers and approvals are resolved and as competition mounts.

Electric and gas distribution companies will continue to merge, serving increasingly larger and more diversified customer bases. As a result, they will have relatively low business risk profiles, as long as regulators approve adequate rates of return on the delivery service. On the local gas distributor side, creditworthiness may improve if these companies sustain good earnings growth, control costs and rates, maintain favorable regulatory relations, unbundle regulated services, and outsource the gas supply function.

Greater demand for interstate pipeline services could offset competitive pressures related to new pipeline construction, the potential for cost increases tied to new safety regulations, and the possible move toward market-based rates from straight-fixed-rate-variable design. In addition, Standard & Poor's expects that the major pipelines will continue to provide the basic cash flow needed to help offset the pricing volatility of the parent company's other investments—usually midstream assets, electric generating plants, and the energy trading and marketing operations.

The usually stable water industry is not without challenges that could affect ratings. These include flat to declining water usage trends, inflation-related operating cost increases, and the replacement of aging pipelines. Nonetheless, tight cost controls, rate relief, and innovative regulatory mechanisms, which allow companies to maintain earnings and cash flow levels while investing in infrastructure renewal programs, should permit this sector to maintain relatively healthy ratings. Another challenge is the possible move toward performance-based rates that force companies to achieve efficiencies to earn reasonable returns, without any degradation in service.

Generally, prospective rating actions for the utility group as a whole are likely to continue to be as much event-driven as predicated on the ongoing qualitative and quantitative characteristics of the existing businesses.

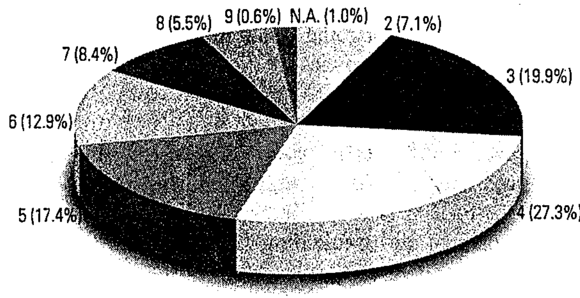
Downgrades Dominate

The predominance of downgrades during the first half was a result of mergers, restructurings, and weakening credit fundamentals.

- Lower ratings for Sierra Pacific Resources and its units Nevada Power Co. and Sierra Pacific Power Co. reflect substantial weakening of key financial parameters resulting from the inability to recover elevated fuel and purchased-power costs in a timely manner. Although state regulators and politicians have provided some support in light of difficult market conditions, the lack of immediate rate relief in the face of elevated power prices throughout the western U.S. continues to pressure credit protection.
- The ratings of MCN Energy Group Inc. (now known as DTE Enterprises) and its subsidiary Michigan Consolidated Gas Co. were lowered, reflecting MCN Energy Group's imminent merger with DTE Energy Co. The ratings reflect Standard & Poor's view that the default risk of each entity within the consolidated DTE Energy family is the same.
- The ratings of IPALCO Enterprises Inc. and its subsidiary Indianapolis Power & Light Co. (IPL) were lowered to reflect the acquisition of IPALCO by lower-rated AES Corp. Standard & Poor's was able to rate IPALCO and IPL higher than its new parent based on AES' intent to ring-fence the companies in a timely manner. Expected enhancements include structural protections, covenants, a pledge of stock, and an independent director.
- Lower ratings for Allegheny Energy Inc. reflect the blended creditworthiness of its regulated and unregulated subsidiaries. The downgrades on the company's unregulated generating units Allegheny Energy Supply Co. LLC (AE Supply) and Allegheny Generating Co. can be traced

Chart 3

Business Profiles



Utility business profiles are categorized from 1 (strong) to 10 (weak).
N.A.—Not available.

Chart 4

Total Debt and Preferred Stock Issuance Through June 30

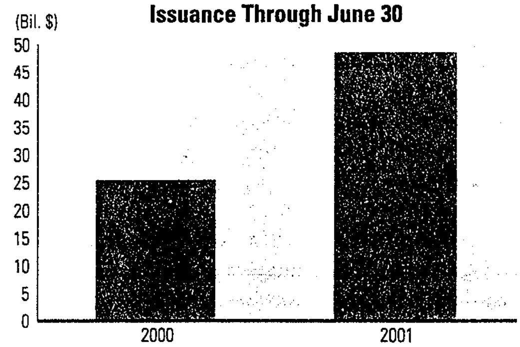
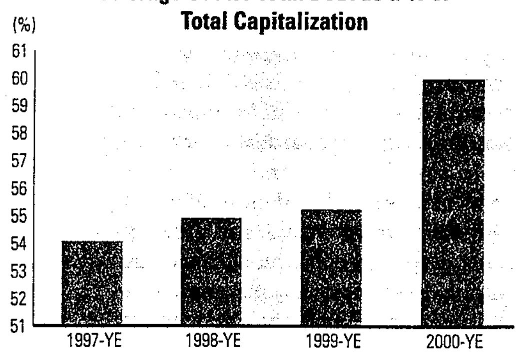


Chart 5

Average Sector Total Debt as a % of Total Capitalization



to the debt-financed acquisition of Global Energy Marketing, a commodity trading operation. In addition, Standard & Poor's now treats AE Supply analytically more as a stand-alone entity in light of recent industry trends and Allegheny Energy's announcement of a potential IPO of AE Supply.

- Reduced creditworthiness for Southwestern Energy Co. and WPS Resources Corp. and its subsidiary Wisconsin Public Service Corp. were attributable mainly to weakening financial measures.
- The ratings of United Water New Jersey and United Waterworks were lowered as a consequence of the downgrade of their ultimate parent, Suez Lyonnaise des Eaux S.A.

Some Credit Improvement

First-half upgrades were attributable to supportive regulation, industry consolidation, and improving business and financial profiles.

- The ratings of DTE Energy were raised reflecting its merger with MCN Energy Group, now known as DTE Enterprises. The ratings are based on Standard & Poor's view that the risk of default risk is the same throughout the organization.
- Higher ratings for NSTAR and its operating subsidiaries, Boston Edison Co., Commonwealth Electric Co., NSTAR Gas Co., and Cambridge Electric Light Co. can be traced to an improved business profile and financial measures that are commensurate with revised ratings.
- The ratings on Northeast Utilities (NU) and its affiliates were upgraded to reflect supportive regulatory decisions that have removed significant uncertainty over the future financial profile of the utilities. Furthermore, corporate restructuring strategies have strengthened the business profile of the individual entities and, accordingly, the consolidated corporation. The expected merger with Consolidated Edison Inc. fell apart, however, and the CreditWatch listings of NU and its several subsidiaries, as well as those of Con Edison, will soon be resolved.
- The ratings on Kinder Morgan Inc. (KMI) were also raised owing to an improving business and financial profile,

as well as recognition of a greater interdependence between KMI and its master limited partnership, Kinder Morgan Energy Partners L.P.

- Reliant Energy Resources Corp. saw its ratings raised as well, reflecting management's indication that gas distribution will continue to be an integral part of parent Reliant Energy Inc.'s future business strategy.
- Higher ratings for Nicor Inc., the parent of Nicor Gas Co., reflect Standard & Poor's consolidated rating methodology, which bases ratings on the consolidated credit profile of the entire family of companies within a corporate structure.

CreditWatch Listings Heat Up

Outlook revisions and CreditWatch listings reflected regulatory decisions, possible corporate restructurings, and merger announcements. CreditWatch listings during the first six months that were attributable to industry consolidation included:

- The ratings on Energy East Corp. and its affiliates were placed on CreditWatch with negative implications following the company's announced acquisition of RGS Energy Group Inc. for $1.4 billion.
- The ratings on Potomac Electric Power Co. were placed on CreditWatch with negative implications after the company offered to acquire Conectiv for $2.2 billion in stock and cash. The ratings on Conectiv were placed on CreditWatch with developing implications. The ratings on higher-rated Conectiv subsidiary Delmarva Power & Light Co. were placed on CreditWatch with negative implications, while those of subsidiary Atlantic City Electric Co. were placed on CreditWatch with developing implications.
- Due to termination of the proposed merger with FPL Group Inc., the CreditWatch implications on the ratings of Entergy Corp.'s subsidiaries Entergy Louisiana Inc., Entergy Arkansas Inc., Entergy Gulf States Inc., Entergy Mississippi Inc., Entergy New Orleans Inc., System Energy Resources Inc., and other affiliates were revised to negative from positive during the first quarter. Subsequently, Standard & Poor's affirmed its ratings on Entergy's units and removed them from CreditWatch. The affirmation reflects an assessment that prospective financial measures should remain adequate for the current level of risk being undertaken. Standard & Poor's also raised its senior secured debt rating on Entergy Louisiana to reflect sufficient overcollateralization.
- The CreditWatch listing on Portland General Electric Co. was revised to developing from negative implications following the announcement by Portland General's parent, Enron Corp., and Sierra Pacific Resources that they have agreed to terminate their purchase and sale agreement.

Other CreditWatch listings and removals included:

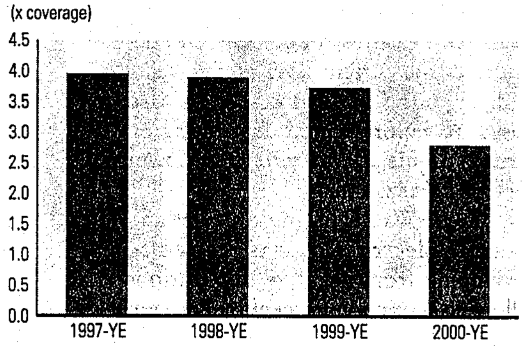
- The ratings on Puget Sound Energy Inc. were on CreditWatch with negative implications owing to the possible unfavorable regulatory ruling, which would pressure the company's already weak financial profile. On April 9, Standard & Poor's affirmed the company's ratings and removed them from CreditWatch. The outlook is negative, which was its status prior to the CreditWatch listing. The action reflects regulatory approval of a new rate power arrangement between Puget Sound Energy and certain large industrial customers.
- The CreditWatch implications on Duke Energy Trading and Marketing LLC (DETM) were revised to negative from developing in response to an arbitration initiated by Duke Energy Corp. against Exxon Mobil Corp. concerning the parties' joint ownership of DETM. Duke Energy is attempting to exercise its right to buy Exxon Mobil's interest in DETM. Standard & Poor's believes that a change in the ownership structure to eliminate one of the partners could increase DETM's default risk. The rating on DETM reflects the credit strength and financial support of the two joint-venture partners, Duke Energy (60% participant) and Exxon Mobil (40%).
- SEMCO Energy Inc.'s ratings were removed from CreditWatch with developing implications following a review of the company's credit profile and SEMCO's intention to forego pursuing other strategic alternatives. The outlook is stable.

Outlook revisions and CreditWatch listings reflected regulatory decisions, possible corporate restructurings, and merger announcements.

- The ratings on DPL Inc. and affiliate Dayton Power & Light Co. were placed on CreditWatch with developing implications in early January following an announcement that the company is exploring strategic options, including the possible sale of all or part of the company. The ratings were subsequently affirmed during the second quarter and removed from CreditWatch. The action followed the company's objective to remain as a stand-alone company. DPL intends to emphasize its regulated transmission and distribution business and unregulated power development, capitalizing on tight capacity conditions in the East Coast Reliability Region. The outlook is stable.
- The ratings on CILCORP Inc. and subsidiary Central Illinois Light Co. were placed on CreditWatch with developing

Chart 6

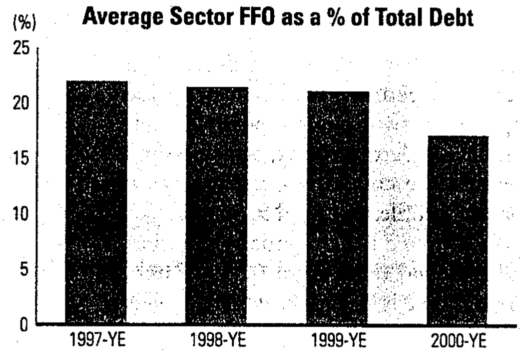
Average Sector FFO Interest Coverage



FFO—Funds from operations.

Chart 7

Average Sector FFO as a % of Total Debt



FFO—Funds from operations.

implications, reflecting uncertainty as to how ultimate parent, AES Corp., will restructure its interest in CILCORP. Options include selling Central Illinois Light's transmission and distribution assets; an outright sale of the entire company, including its generation assets; and/or some type of sale-leaseback arrangement.

- The CreditWatch implications on Green Mountain Power Corp. were revised to developing from negative, reflecting an agreement that was reached between the company and the Vermont Public Service Commission that resolved regulatory uncertainties and established a framework for improved financial performance. The ratings on the company were subsequently removed from CreditWatch early in the second quarter and assigned a positive outlook. The outlook reflects expectations for continuous regulatory support that should provide Green Mountain with an opportunity to strengthen its financial condition.

OUTLOOK CHANGES DECIDEDLY NEGATIVE

The rating outlook revisions to negative from stable or positive can be traced principally to subpar financial parameters, and for some companies increasing business risk associated with expansion of unregulated activities as well.

- The rating outlooks on Peoples Energy Corp. (PEC) and its wholly owned gas utility subsidiaries, Peoples Gas Light & Coke Co. and North Shore Gas Co., were revised to negative from stable to reflect weakness in the company's consolidated financial condition, as well as ongoing investments in diversified businesses. The negative outlooks for the utility units are attributable to the potentially adverse effect on their credit quality of the parent's strategy of relying increasingly on diversified businesses to expand consolidated earnings.
- Kansas City Power & Light Co.'s outlook was changed to negative from stable owing to continued weakness in the company's financial condition relative to its average business risk profile and ongoing investments in riskier unregulated operations (primarily fiber optics and merchant generation).
- The outlook on Southwest Gas Corp. was changed to negative from stable, reflecting the firm's weakening financial profile as a result of increased debt leverage used to finance infrastructure growth.
- Cascade Natural Gas Corp.'s rating outlook was revised to negative from positive due to the accumulation of some \$26 million in deferred balances stemming from under-recovery of gas costs, uncertainty as to when such balances will be recovered, and the company's resulting weak financial condition.

On a favorable note, El Paso Energy Partners L.P.'s credit outlook was changed to positive from stable, reflecting significant growth opportunities in the midstream gas business, the potential for improving bondholder protection measures, and the commitment of general partner El Paso Corp. to its master limited partnership, El Paso Energy Partners. CW

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

5. Standard & Poor's
6. Morningstar
7. BARRA

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

President's Letter

2016 Financial Review

Last year, I wrote to you about the profound transformation that our industry is leading across the nation. As our industry continues to evolve, one thing remains constant—our commitment to meeting customers' needs by building and using smarter energy infrastructure, by providing even cleaner energy, and by creating the energy solutions they want. This commitment guides us, and also provides opportunities to collaborate and make progress on key policy priorities.

To meet customers' changing needs, we are transitioning to even cleaner generation sources and are leading the way on renewables. In just 10 years, the mix of sources used to generate electricity has changed dramatically and is increasingly clean. In 2016, natural gas use surpassed coal as a main source of electricity in the U.S.—the first time that a fuel other than coal has supplied the bulk of the nation's power. Electric companies also are the largest investors in renewable energy in the U.S. Virtually all of the wind, geothermal, and hydropower in the country—and the majority of installed solar capacity—is provided by electric companies.

We are building smarter energy infrastructure, and our investments are creating additional jobs and are making the energy grid more dynamic and more secure for all customers. We are investing in energy efficiency and are providing customers the energy solutions they want. We also are partnering with leading innovative companies and start-ups to shape the future using technology.

Today, the Edison Electric Institute's (EEI's) member companies connect millions of Americans in their homes, communities, businesses and industries, and around the nation. We are an integral and robust component of our nation's economy. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States—this includes nearly 2.7 million directly provided jobs that result from the industry's operations and investments. We also are creating long-term solutions to address the ongoing need for a skilled, diverse workforce in the future.

As you will see in this year's Financial Review, EEI's investor-owned electric company members continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the third straight year in 2016, after increasing from the BBB average that had previously held since 2004. Ratings upgrades were a very favorable 73.1% of total credit actions, resulting from companies' increased focus on regulated operations, achieved through spin-offs and divestitures, as well as the effective management of regulatory risk. The improved credit quality greatly supports the continued surge in capital expenditures, which rose by $8.5 billion, or 8.2%, to a new record high of $112.5 billion in 2016.

For the sixth consecutive year, all of the EEI Index companies paid a dividend in 2016, and strong dividend yields continue to support utility stocks. The industry's dividend yield at the end of 2016 stood at 3.4%, and 40 electric companies, or 91% of the industry, increased their dividend last year, the largest percentage on record.

Looking ahead, I am optimistic about our industry's future. EEI's member companies are committed to providing reliable, affordable, secure, and increasingly clean energy to drive our nation's economy and power our everyday lives. By continuing to lead together on the issues driving the electric power industry's transformation, EEI and our member companies will demonstrate Power by Association, and we will deliver America's energy future.

We truly value the partnership that we share with the financial community.

Thomas R. Kuhn

Thomas R. Kuhn

President
Edison Electric Institute

EEI

WISHING

David K. Owens

THE BEST IN HIS RETIREMENT

For nearly four decades, David has provided pioneering leadership to EEI and to our member companies. David will be sorely missed by his colleagues and by a legion of friends and admirers throughout the electric power industry and beyond.

Industry Surveys

Electric Utilities

February 2017

Christopher Muir
Equity Analyst

powered by data from S&P Global

Performance

Industry Profile

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Real Estate Investment Trusts
Road & Rail
Semiconductors & Equipment
Software
Specialty Retail
Technology Hardware
Telecommunications
Textiles, Apparel & Luxury Goods
Thrifts & Mortgage Finance

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EXECUTIVE SUMMARY

◆ CFRA's fundamental outlook for the electric utilities and multi-utilities industries is neutral for the next 12 months. Recent rate increases for many utilities will likely help mute the effect of low customer growth rates and unfavorable weather. A constant effort to control costs in both the electric utilities and multi-utilities industries also plays a part in helping to generate earnings per share (EPS) growth.

◆ This *Survey* discusses multi-utilities, and which metrics are highlighted and differentiated from the electric utilities industry. CFRA notes that within the multi-utilities industry, only 23% of operating revenues in 2015 were from gas distribution. Hence, for the most part, metrics for multi-utilities track electric utilities metrics more closely than gas utilities metrics.

◆ Revenues for electric utilities have been boosted by hotter-than-normal summer weather over the past several years. In 2016, cooling-degree-day counts were higher than normal, but below the levels in 2015. Last year, cooling-degree-days were 6% higher than normal, versus 19% higher in 2015. CFRA projections in this *Survey* assume a return to normal cooling-degree-days in 2017, which would put significant pressure on revenues. Moreover, revenues for multi-utilities will likely be hurt by lower gas demand driven by fewer-than-normal heating-degree-days last year.

◆ Electric utilities revenues have also been pressured by the effects of lower gas prices on power prices. Unregulated and uncontracted generation is subject to market prices for power, which means low power prices as Henry Hub gas prices fell from $4.41 per million British thermal unit (MMBtu) on November 20, 2014 to a low of $1.49 on March 4, 2016, before rising to $3.44 on January 26, 2017. Continued high natural gas storage levels and strong production trends will likely keep downward pressure on gas prices, even though gas-directed drilling rig activity has fallen sharply. However, due to an anticipated increase in chemical and electric power demand, and more normal winter weather in 2017, CFRA expects natural gas prices to hit $3.82 by the end of 2017, helping to boost power prices, before falling to $3.65 by the end of 2018. Meanwhile, natural gas prices are projected to average $3.54 in 2017 and $3.81 in 2018, according to the US Energy Information Administration (EIA).

◆ CFRA expects electric utilities rate increases to benefit revenues in 2017. Rate-case activity has been relatively strong over the past 10 years, with a five-year annual average of around 60 cases and $2.5 billion in rate increases. CFRA expects about 55 cases to be decided this year (although none had been decided as of January 18, 2017), with a total revenue increase of more than $2.0 billion from 2016. We also think that the long-term steady decline in allowed returns will likely reverse in 2017 as interest rates are expected to continue to move higher.

◆ Earnings before interest and taxes (EBIT) margins ticked up for electric utilities in the second and third quarters of 2016, due to higher rates and growing customer numbers, despite cooler summer weather. Margins for multi-utilities recently increased as the cost of gas fell and as some companies sold or spun-off lower-margin exploration and production, as well as transportation and storage businesses. For 2017, CFRA expects companies in the electric utilities and multi-utilities industries to be hurt by less favorable summer weather compared with last year, but helped by more favorable winter weather, rate increases, customer growth, and expense growth control efforts.

◆ Normalized EPS growth has been stagnant for both electric utilities and multi-utilities since 2008, with some choppiness due to weather variations. Given the lower revenues estimated by

CFRA for 2016 and the anticipated pressure on revenues in 2017 (driven by fewer cooling-degree-days), we think EPS decreased slightly from 2015 to 2016 and that it will increase incrementally from 2016 to 2017.

◆ After slowing in 2013 and 2014, electric utilities dividends grew 3.1% in 2015 and 3.9% in the third quarter of 2016, year over year. On the other hand, multi-utilities dividends have grown steadily since 2005, increasing 8.6% in 2015 and 6.1% year over year in the third quarter of 2016. Due to high payout ratios, CFRA thinks dividend growth for electric utilities will likely be measured for the foreseeable future. We think multi-utilities dividend growth will also be measured, although the payout ratio gives multi-utilities slightly more room to raise dividends.

◆ CFRA foresees continued high levels of capital spending by the electric utilities industry, both on regulated and unregulated investments, but we think it could hit a temporary peak in the next few years. Regulated capital spending comprises spending on infrastructure replacement, new transmission and distribution facilities and lines, and regulated power plants, including new nuclear units currently under construction. Unregulated spending will mostly focus on new natural gas-fired combined-cycle power plants, and we think investment in solar and wind generation projects is also likely.

◆ Whole company merger and acquisition (M&A) activity in the utilities sector picked up pace over the past two years, with the acquisitions of Questar by Dominion Resources, Piedmont Natural Gas by Duke Energy, and AGL Resources by Southern Co. These acquisitions of gas companies by electric utilities or multi-utilities were driven by a perceived need to increase exposure to natural gas after the Environmental Protection Agency (EPA) released its final version of the Clean Power Plan (CPP). CFRA thinks M&A activity could increase in 2017, given the expected removal of the CPP by the new Trump administration. Other M&A transactions include the acquisitions of TECO Energy by Emera, ITC Holdings by Fortis, and Westar by Great Plains Energy.

◆ CFRA thinks electric utilities valuations are high, with price-to-earnings (P/E) valuations and enterprise value-to-earnings before interest, tax, depreciation, and amortization (EV/EBITDA) valuations well above historical levels. The electric utilities industry has benefited from several years of solid earnings growth and low interest rates. Rapidly rising interest rates could hurt valuations, as share prices in the electric utilities and multi-utilities industries would need to drop to make dividend yields competitive with fixed income investments.

◆ Against the backdrop of a steadily improving macroeconomic environment (slowly rising customer growth, higher housing starts, and increasing industrial usage), long-term revenue trends for the electric utilities industry are likely to remain modestly positive, although CFRA sees some challenges to revenue growth in the next year or two due to summer temperatures returning to more normal levels. We also see near-term challenges to earnings growth due to the weather, but we expect long-term earnings growth to benefit from rate increases, customer growth, and increasing industrial sales.

◆ CFRA expects pressure on revenues for the electric utilities industry in 2017, leading to slightly lower earnings per share (EPS) this year. Strong capital spending will likely help to drive rate increases and future EPS growth. We think price-to-earnings (P/E) ratios are relatively high, considering our forecast of lackluster earnings growth and limited dividend growth for the near future.

SECTOR OVERVIEW

Year to date through February 24, 2017, the S&P 500 utilities index, which represented 3.2% of the S&P 500 index, was up 5.6% in price, compared with a 5.7% increase for the S&P 500. In 2016, this sector index rose 12.2%, versus a price increase of 9.5% for the S&P 500. There are four sub-industry indices in the utilities sector. The electric utilities sub-industry is the largest, representing 62.7% of the sector's market value, while the independent power producers & energy traders sub-industry is the smallest, accounting for around 2.1% of the sector.

The utilities sector is projected to record a 3.1% year-over-year decline in operating earnings per share (EPS) in 2017, compared with the estimated EPS gain of 10.9% for the S&P 500, according to S&P Capital IQ consensus estimates. During 2016, this sector is estimated to have posted a 7.3% rise in EPS, versus a 0.3% increase for the S&P 500. In addition, revenues for the sector are forecast to decline 2.7% in 2017 versus the projected gain of 5.8% for the S&P 500. The sector's price-to-earnings (P/E) ratio of 17.9x, based on consensus operating EPS estimates for 2017, is essentially equal to the S&P 500's forward P/E.

The consensus long-term EPS growth estimate for the utilities sector is 5.2% versus the S&P 500's 11.8%, giving the sector a P/E-to-projected EPS growth rate (PEG) ratio of 3.4x, which is significantly higher than the 1.5x PEG ratio projected for the S&P 500. Finally, this sector pays a dividend yield of 3.6%, compared with the 2.0% yield for the S&P 500.

UTILITIES SECTOR AND INDEX PRICE PERFORMANCE
(as of January 31, 2017)

			PRICE CHANGES *(in percent)*				
INDUSTRIES	INDEX VALUE	% OF S&P 1500	2017 JANUARY	3-MONTHS	YEAR-TO-DATE	2016	5-YEAR CAGR
Utilities	288.09	3.30	1.19	0.30	1.19	13.69	7.82
Electric Utilities	292.36	1.92	1.12	(1.19)	1.12	11.91	6.11
Gas Utilities	734.94	0.19	2.06	6.86	2.06	21.04	13.40
Independent Power Producers & Energy Traders	55.33	0.06	10.68	14.79	10.68	19.68	(2.32)
Multi Utilities	87.39	1.03	0.68	1.17	0.68	15.59	9.99
Water Utilities	1,507.49	0.10	1.03	0.69	1.03	9.43	14.81
S&P 500	2,278.87	89.25	1.79	7.18	1.79	9.54	11.67
S&P MidCap 400	1,687.19	7.48	1.60	11.77	1.60	18.73	12.49
S&P SmallCap 600	834.20	3.28	(0.45)	15.45	(0.45)	24.75	13.54
S&P Composite 1500	529.90	100.00	1.70	7.77	1.70	10.65	11.79

Source: S&P Dow Jones Indices.

ETF Market Flows and Investing Landscape

◆ Beside stocks, exchange-traded funds (ETFs) are increasingly used by investors. ETFs offer investors benefits such as market focus, intraday market liquidity, and lower fees relative to other diversified financial instruments. Investors interested in exploring opportunities aligned with either the broad utilities sector or, more specifically, the electric utilities industry, may want to consider one or more of the ETFs discussed in this *Survey*.

◆ In 2016, $29.1 billion was added to all sector ETFs, while ETFs related to the utilities sector had inflows of $2.0 billion, after experiencing outflows of $3.4 billion in 2015. Through January 2017, utilities ETFs had outflows of $930 million.

SECTOR ETF INFLOWS
(total inflows for the period ended, in $, millions)

SECTOR	YEAR ENDED 2016	FIRST MONTH, 2017
Consumer Discretionary	(5,272)	364
Consumer Staples	(2,354)	(287)
Energy	6,343	874
Financials	4,992	852
Health Care	(3,241)	(322)
Industrials	6,919	622
Information Technology	(697)	932
Materials	12,620	1,234
REITs	7,502	1,587
Telecommunication Services	267	240
Utilities	2,040	(930)

Source: State Street Global Advisors.

◆ There are no dedicated electric utilities industry ETFs. However, the industry is the largest in many diversified utilities sector ETFs. The three largest, market-cap weighted products, iShares US Utilities (IDU), Utilities Select Sector SPDR (XLU), and Vanguard Utilities (VPU), all have more than 57% of their assets in electric utilities.

ETFS WITH MEANINGFUL ELECTRIC UTILITIES EXPOSURE

COMPANY TICKER	ETF NAME	ASSETS UNDER MANAGEMENT *(in $, millions)*	NET EXPENSE RATIO
XLU	Utlities Select Sector SPDR	6,870	0.14
VPU	Vanguard Utilities	2,318	0.10
FXU	First Trust Utilities AlphaDEX	1,452	0.66
IDU	iShares US Utilities	682	0.44
RYU	Guggenheim S&P 500 Equal Weight Utilities	211	0.40
FUTY	Fidelity MSCI Utilities	180	0.08

Source: CFRA ETF Report January 12, 2017.

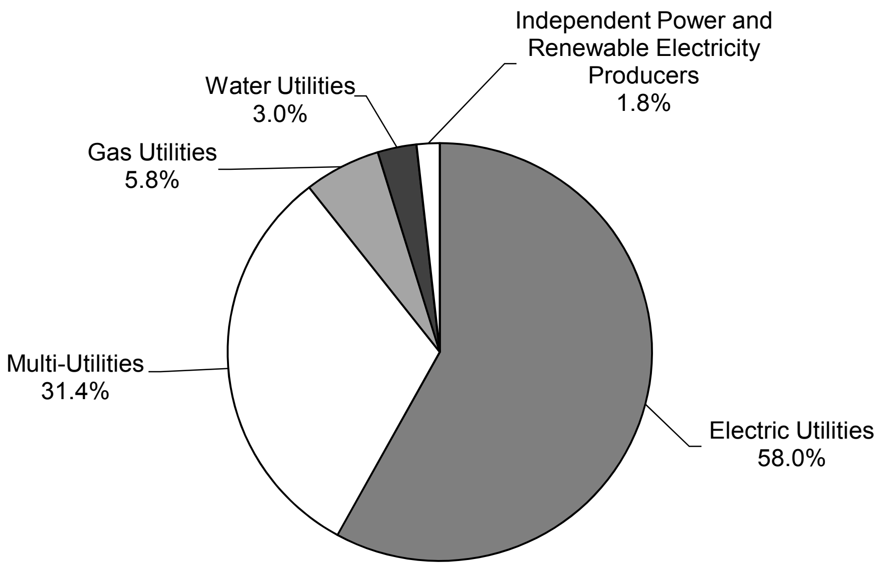
◆ In 2016, XLU, VPU, and IDU experienced inflows of $443.6 million, $379.2 million, and $10.2 million, respectively. There are additional products to consider, including First Trust Utilities AlphaDEX (FXU), a fundamentally weighted offering that has 44.9% of its assets in electric utilities, but also has exposure to telecommunications companies. FXU pulled in about $1.1 billion last year.

INDUSTRY OVERVIEW

Industry Weighting

◆ The utilities sector makes up 3.1% of the S&P 500 and 3.3% of the S&P 1500, as of February 10, 2017. There are five industries in the S&P 1500 utilities sector: electric utilities, multi-utilities, gas utilities, water utilities, and independent power & renewable electricity producers.

UTILITIES MARKET-CAPITALIZATION WEIGHTINGS BY COMPANY
(as of January 17, 2017)



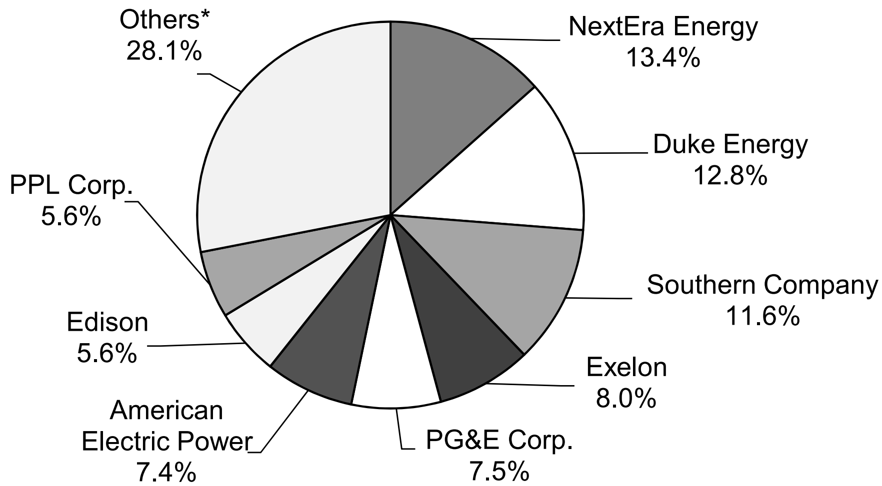
Source: S&P Dow Jones Indices.

◆ From a stock price perspective in 2015, the S&P 1500 utilities index underperformed, falling 8.0% compared with a 1.0% decrease in the S&P 1500; electric utilities stocks were down 8.9% and multi-utilities declined 5.6%. In 2016, the utilities index rose 13.7%, higher than the 10.6% increase for the S&P 1500.

◆ However, after considering dividends, the utilities sector's performance looked better. Total return for the utilities sector was 27.4% in 2014, -4.5% in 2015, and 17.7% in 2016 compared with 13.1% recorded for the S&P 1500 in 2014, 1.0% in 2015, and 13.0% in 2016. The total return for the electric utilities industry was 30.1% in 2014, -5.2% in 2015, and 16.1% in 2016. For the multi-utilities industry, the total return was 27.5% in 2014, -2.1% in 2015, and 19.6% in 2016.

◆ The electric utilities industry is somewhat fragmented, although there are several large companies in the industry. There are 22 electric utilities in the S&P 1500, and the three largest companies have a combined 37.9% market-capitalization weighting, while the largest eight have 72.1%.

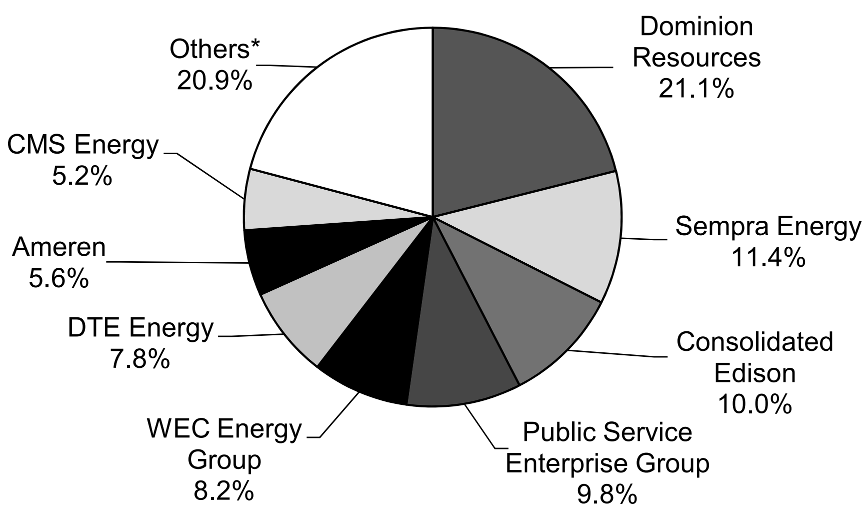
ELECTRIC UTILITIES MARKET-CAPITALIZATION WEIGHTINGS BY COMPANY
(as of Januray 19, 2017)



Total: $414.9 Billion

*Others include: Xcel Energy, Eversource Energy, FirstEnergy, Entergy, Pinnacle West Capital, Alliant Energy, Westar Energy, OGE Energy, Great Plains Energy, IdaCorp, Hawaiian Electric Industries, ALLETE, PNM Resources, and El Paso Electric.

MULTI-UTILITIES MARKET-CAPITALIZATION WEIGHTINGS BY COMPANY
(as of January 19, 2017)



Total: $224.8 Billion

*Others include: CenterPoint Energy, SCANA Corp., NiSource, MDU Resources Group, Vectren, Black Hills, Northwestern, and Avista.

Source: S&P Capital IQ.

◆ The electric utilities industry is comprised of companies that own regulated electric distribution utilities, each with a monopoly in its own service area for the delivery of electricity. In return for the monopoly status, local, state, and federal governments regulate the utilities. Some utilities own regulated generation assets for use in their systems, some own merchant generation to produce electricity for wholesale markets, and some do not own generating assets.

◆ Multi-utilities are companies that are comprised of both electric utilities and gas utilities. In 2015, gas utilities revenues within the S&P 1500 multi-utilities industry were only 23.2%. As a result, the economic fortunes for multi-utilities are similar to those of electric utilities. In the following “Industry Overview” sections, where there are significant differences between electric utilities and multi-utilities, CFRA will provide a brief commentary.

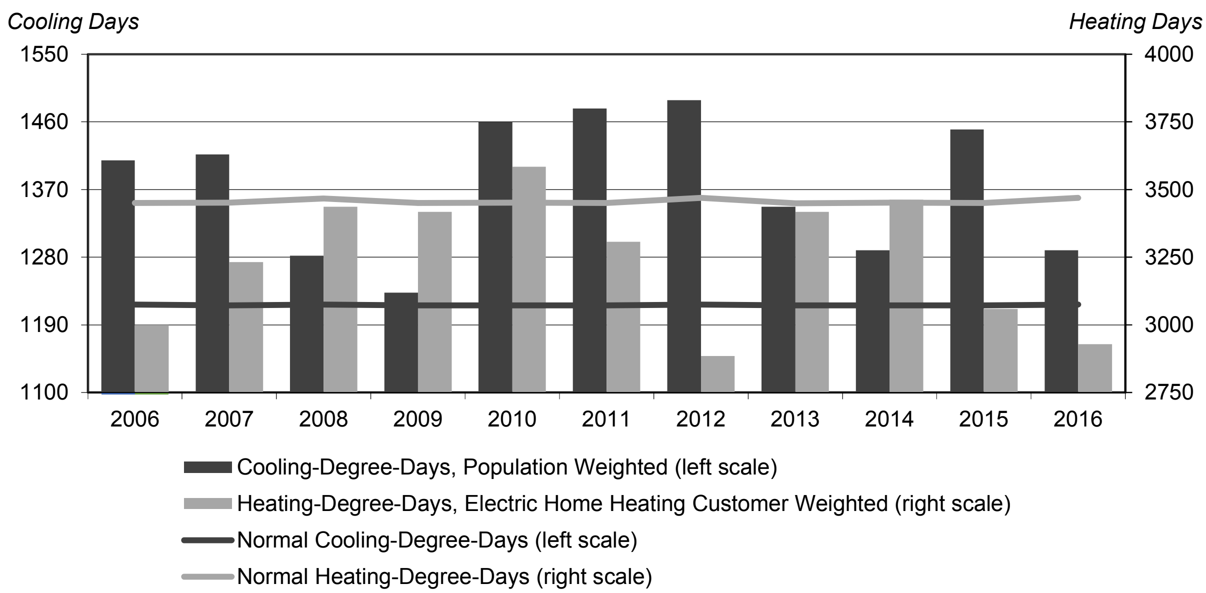
◆ The multi-utilities industry is also somewhat fragmented, with several large companies dominating the industry. There are 16 multi-utilities in the S&P 1500, and the largest four companies make up 52.4% of the industry’s market capitalization, while the largest eight have 79.3%.

Industry Revenues

Revenues

◆ Over the past five years, annual aggregate value-weighted revenues per share for the electric and multi-utilities industries in the US have been affected by weather patterns. The drop in total revenues during 2012 corresponded with the acquisition of Constellation Energy by Exelon Corp. and the integration of Constellation’s trading operations into Exelon’s business. CFRA thinks hot summer weather in 2015 helped revenues to grow, while cooler summer weather in 2016 led to a decline in revenues.

COOLING- AND HEATING-DEGREE-DAYS IN THE US

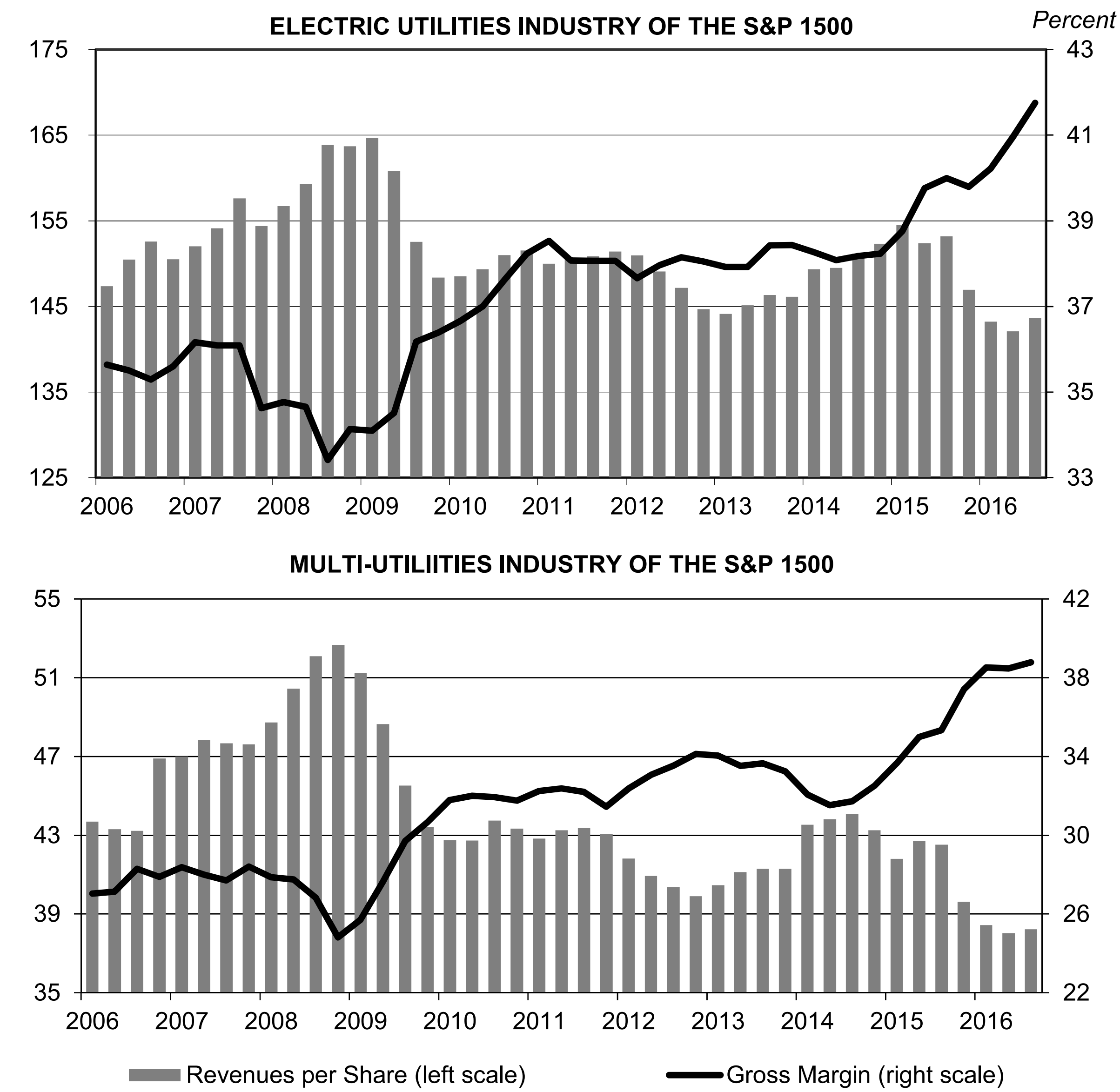


Sources: National Oceanic and Atmospheric Administration, National Weather Service, and Climate Prediction Center.

◆ Base revenue growth is benefiting from improving industrial revenues driven by a slowly improving economy, rate increases driven by significant levels of capital spending on replacing aging infrastructure, new power plants, and new transmission lines, according to CFRA analysis. Strong economic growth through 2009 helped revenues grow until the recession. Since then, revenues have largely been driven by weather, with an upward trend due to customer growth and higher customer rates.

◆ While the electric utilities and multi-utilities industries will likely continue to benefit from rate increases and an improving economy, cooling-degree-days have remained above normal for an extended period of time, and there is a risk of significant pressure on revenues if summer weather returns to normal or falls below normal in the next few years. Investors may be getting used to the prolonged weather benefit. CFRA expects a drop in cooling-degree-days during the summer of 2017.

REVENUE PER SHARE AND GROSS MARGIN
(aggregate value weighted per share, $, last four quarters)

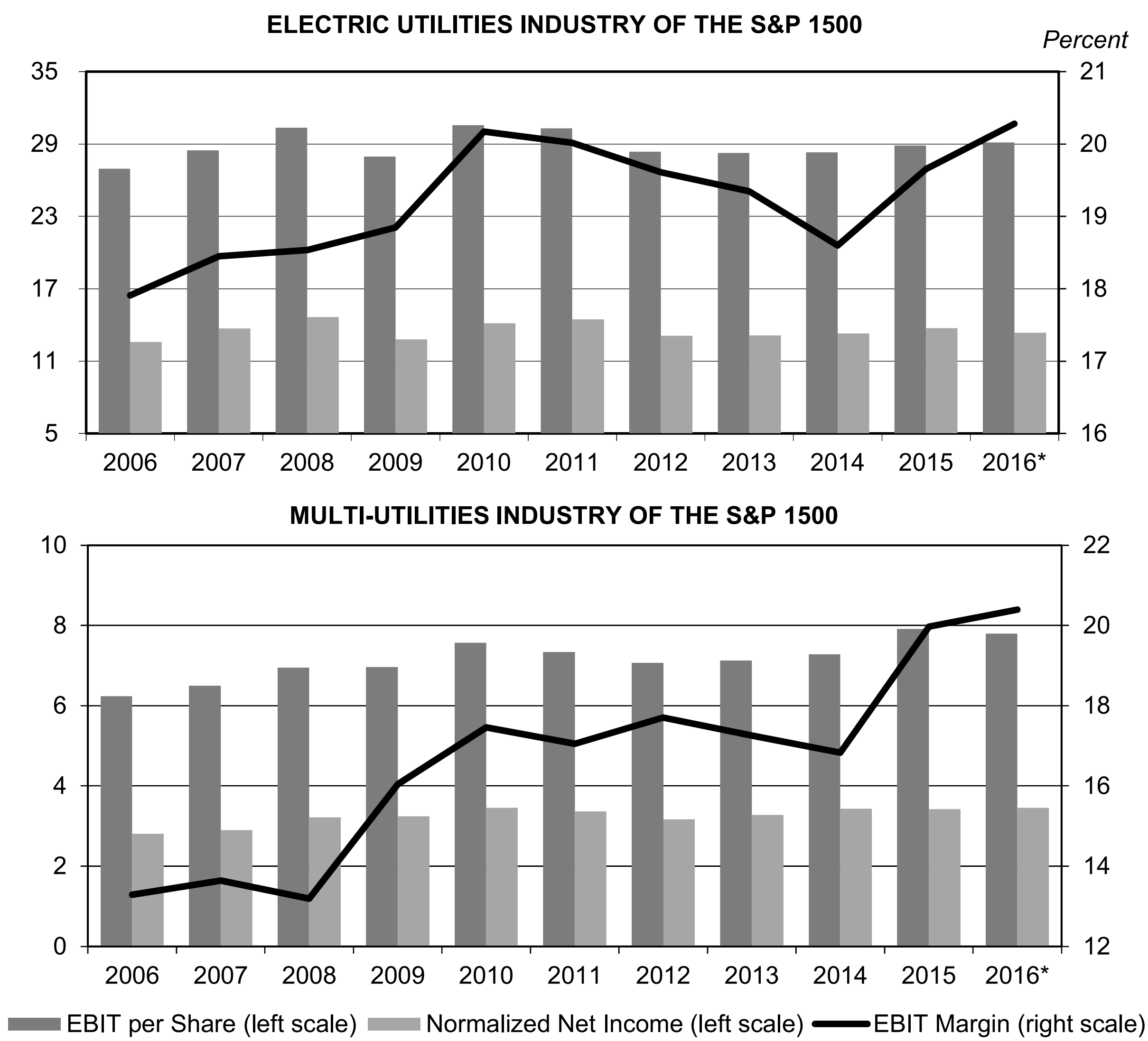


Source: S&P Capital IQ.

Gross Margins

◆ Electric utilities and multi-utilities have benefited from the falling costs of fuel and purchased power in recent years. Prices of coal for use in electric power plants increased from about $40 per ton in 2008 to the mid-$40 range thereafter, before reaching a high of $46.65 in 2011. In 2015, coal prices averaged $42.86. CFRA thinks lower coal, gas, and oil prices had a positive effect on margins in 2016. Gross margins for multi-utilities, while they are similar in directional moves to electric utilities, reflect the lower margins of the gas businesses owned by these companies.

EBIT MARGINS AND NORMALIZED EARNINGS PER SHARE
(aggregate value weighted per share, $)



*Data represents last four quarters ending in the third quarter.

Source: S&P Capital IQ.

◆ Fuel and purchased power costs will likely begin to creep upward, but CFRA thinks fundamentals will keep natural gas and coal prices from rising much through 2017. With that said, as coal plant retirements begin to occur because of recent Environmental Protection Agency (EPA) regulations and low gas prices, we foresee downward pressure on future coal prices and upward pressure on natural gas prices.

Industry Profits

EBIT Margin

◆ Due to the inability to create growth through the introduction of new products, electric utilities are always striving to control costs. As a result, earnings growth often exceeds revenue growth. Multi-utilities earnings before interest and taxes (EBIT) margins track electric utilities margins fairly well, but the typically lower-margin levels reflect the industry's ownership of lower-margin gas utilities. Margins for multi-utilities recently increased as the cost of gas fell and as some companies sold or spun-off lower-margin exploration and production, as well as transportation and storage businesses.

◆ In recent years, several large acquisitions in the electric utilities industry yielded significant savings for the acquirer. Improving EBIT margins will likely be tied to future merger and acquisition (M&A) activities, with several major deals that closed in 2016. These transactions were mostly electric utilities and multi-utilities acquiring gas utilities. Although the acquired companies are dwarfed by the acquiring companies, the lower margins of the gas utilities acquired are likely to put some downward pressure on margins in 2017.

◆ Profits for unregulated generating assets of electric utilities and multi-utilities could begin to improve in the foreseeable future. There are many coal-fired power plants slated for closure over the next several years. As total electric demand growth outstrips capacity growth (due to the effect of the closures), CFRA expects profitability to improve for the remaining plants.

Net Income

◆ Net income has tracked EBIT relatively closely. CFRA saw net income rise in 2015, largely due to rate increases, customer growth, improving industrial sales, hotter summer weather, and generally lower interest expense. Approved rate increases totaled about $1.9 billion in 2015 and $2.3 billion in 2016, according to SNL, a source of utilities data and a division of S&P Global. We see 2017 being affected by higher interest costs due to increased capital spending levels and higher operating expenses offset by rate increases and maturing long-term debt being refinanced at cheaper rates.

◆ Going forward, assuming a return to normal summer temperatures, CFRA thinks net income will come under pressure. However, we continue to expect rate cases to play a significant role, as we estimate that rate increases will total over $2 billion in 2017. In addition, we see customer growth increasing as the economy slowly improves.

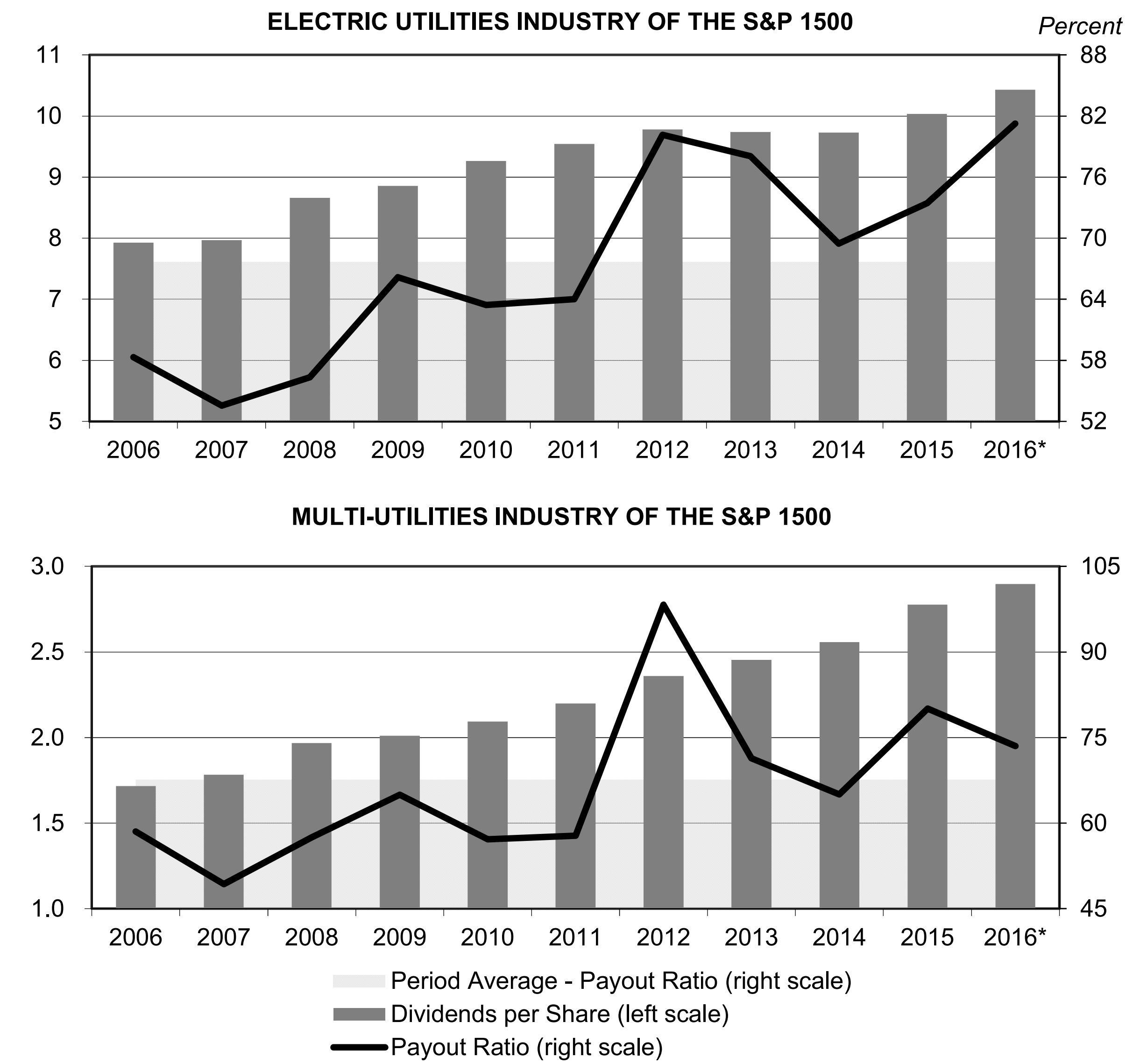
◆ Overall, CFRA thinks net income for the electric utilities industry will be pressured in 2017, but will subsequently return to a more normal growth rate in the 3%–5% range. CFRA sees this increase mostly driven by customer growth, rate increases, and continued improvements in industrial sales as the economy improves. We expect similar pressures on multi-utilities, but the multi-utilities industry will likely fare better if winter weather returns to more normal (colder) weather over time.

Dividends per Share

◆ Trailing 12-month dividends have generally been rising faster than earnings per share (EPS) since 2007. Many companies in the electric utilities and multi-utilities industries have shed more risky unregulated operations, or reduced the scope of their unregulated operations in order to manage their risk more easily. As the earnings quality of these companies improves, their managements target higher dividend payout ratios.

◆ Dividends remain an important factor when investing in electric utilities and multi-utilities. Rising interest rates are a potential source of pressure on electric utilities stocks. As yields on other investment assets increase in a rising interest-rate environment, electric utilities and multi-utilities will likely have less room to raise their dividends due to the already high payout ratios.

DIVIDENDS PER SHARE AND PAYOUT RATIO
(aggregate value weighted per share, $)



*Data represents last four quarters ending in the third quarter.

Source: S&P Capital IQ.

◆ Electric utilities yields for the S&P 1500 utilities sector stood at 3.5% on January 19, 2017, compared with a 10-year treasury yield of 2.5%. If the 10-year treasury yield rose 0.25% over a period of one year, and if utilities dividends increased 4.0% during the same period, then shares would have to fall 2.9% to maintain the spread between the 10-year treasury yield and the electric utilities yield. However, if the 10-year treasury yield rose 0.5%, then utilities shares would have to fall 8.9% to maintain the spread. The speed of future interest-rate increases and the slope change of the yield curve will likely determine how much of an impact these changes will have.

◆ CFRA estimates that electric utilities dividends will rise at a rate of about 3%–4% in 2017, and then grow slightly faster in subsequent years. Some electric utilities companies have increased their targeted dividend payout ratios in recent years, and we see payout ratios rising even higher this year due to our expectations for earnings growth pressure and dividend increases.

Industry Capital Expenditures

Capital Expenditures

◆ Electric utilities companies face a growing customer base that uses more and more electricity. To meet the challenge, the electric utilities industry can invest in new assets to generate and deliver power, or it can promote customer efficiency. Efficiency efforts are often only a temporary measure to reduce demand growth, delaying when new power plants might be needed. Other capital spending targets grid modernization and replacement of aging infrastructure assets.

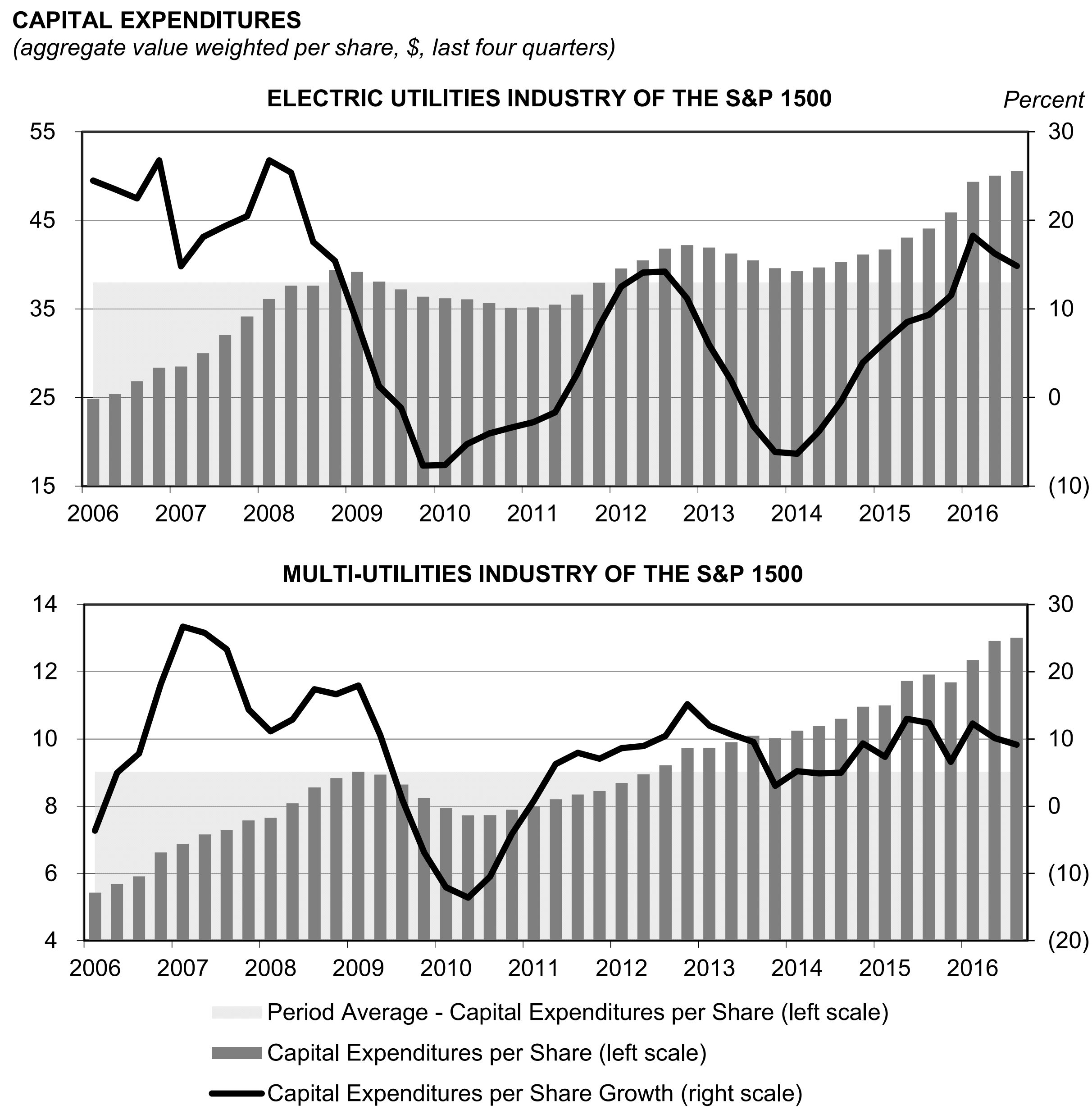
◆ While investments in regulated assets are guaranteed a set rate of return through a company's regulated customer rates, investments in merchant power plants are subject to the market forces in which they operate. As a result, unregulated merchant power plants are often a riskier proposition. However, in some markets, especially in the Northeast, much of the generation fleet has become deregulated. Some companies try to enter into long-term power supply contracts that reduce risks related to the merchant assets. In addition, many companies are investing in both regulated and unregulated solar and wind assets.

◆ Capital expenditures have risen significantly since 2005, and CFRA expects them to remain at relatively high levels. Southern Co. is building new nuclear generation that will likely drive high capital spending levels for the company through 2018. Other companies are also investing in new natural gas-fired combined-cycle power plants to meet rising demand. In addition, many companies are investing in expensive regulated and unregulated solar and wind generating assets to meet renewable power requirements set by state regulators. Many unregulated projects are built after securing multi-year contracts for the output from the plant.

◆ New electric transmission projects are also a source of capital spending, though they tend to have lower capital requirements than a new electric power plant. Interstate transmission lines are regulated by the Federal Energy Regulatory Commission (FERC) and benefit from a formula-based ratemaking process that provides more certainty about the projects' profitability.

◆ Since 2011, capital spending growth for multi-utilities has been much steadier than that for electric utilities. This is because multi-utilities are able to shift some spending between gas and electric-oriented projects as market conditions change. In addition, in recent years, many utilities have been able to accelerate spending on cast iron and bare steel gas main replacement; regulators have allowed utilities to begin earning on those investments as the capital is deployed. For instance, Scana Corp. is a multi-utility that is building new nuclear generation.

◆ CFRA expects capital spending levels to remain high, as some companies continue to prepare for the possibility of new environmental regulations that seem likely to reduce coal-fired capacity even more. This reduction in coal capacity will drive increased spending on new combined-cycle natural gas-fired power plants, in our view. We also see additional state renewable power generation requirements driving more spending on wind and solar.



Source: S&P Capital IQ.

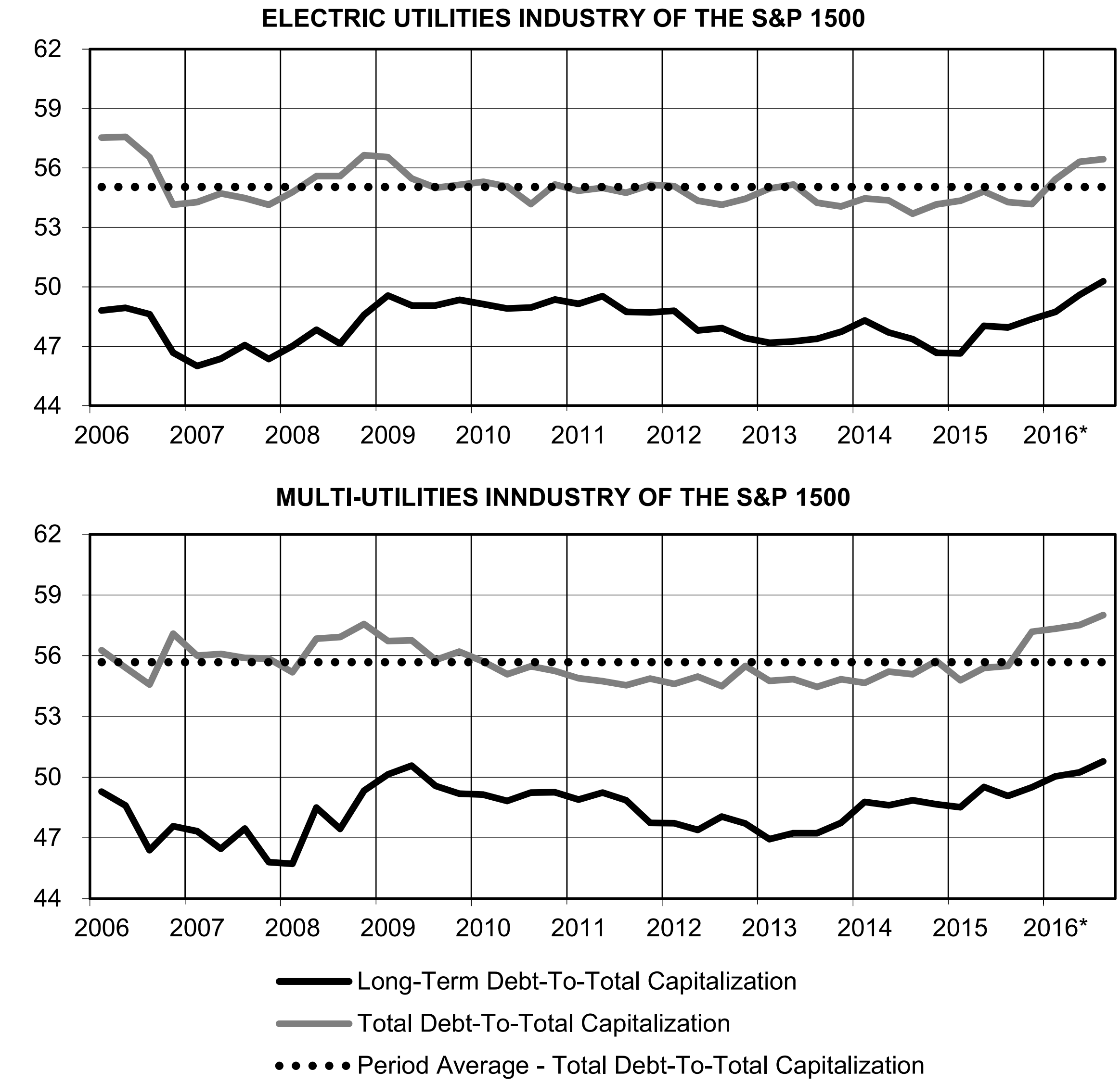
Industry Balance Sheet

Long-Term Debt-To-Capitalization

◆ From 2009 to the first quarter of 2015, the aggregate value-weighted per share long-term debt-to-capitalization ratio for electric utilities in the S&P 1500 trended downward (falling from 49.6% in the first quarter of 2009 to 46.6% in the first quarter of 2015), but it has since trended upward, reaching 50.3% in the third quarter of 2016. CFRA thinks the decline was driven by relatively high cash generation levels, enabling some companies to keep debt levels in check.

◆ The long-term debt-to-capitalization ratio will likely rise somewhat in 2017, as CFRA expects elevated capital spending levels to help lead the ratio higher. Utilities companies are also using more of their cash for share repurchase programs and higher dividends, contributing to the need for more debt.

DEBT-TO-CAPITALIZATION RATIOS
(last four quarters, in percent, quarterly)



*Data through third quarter.

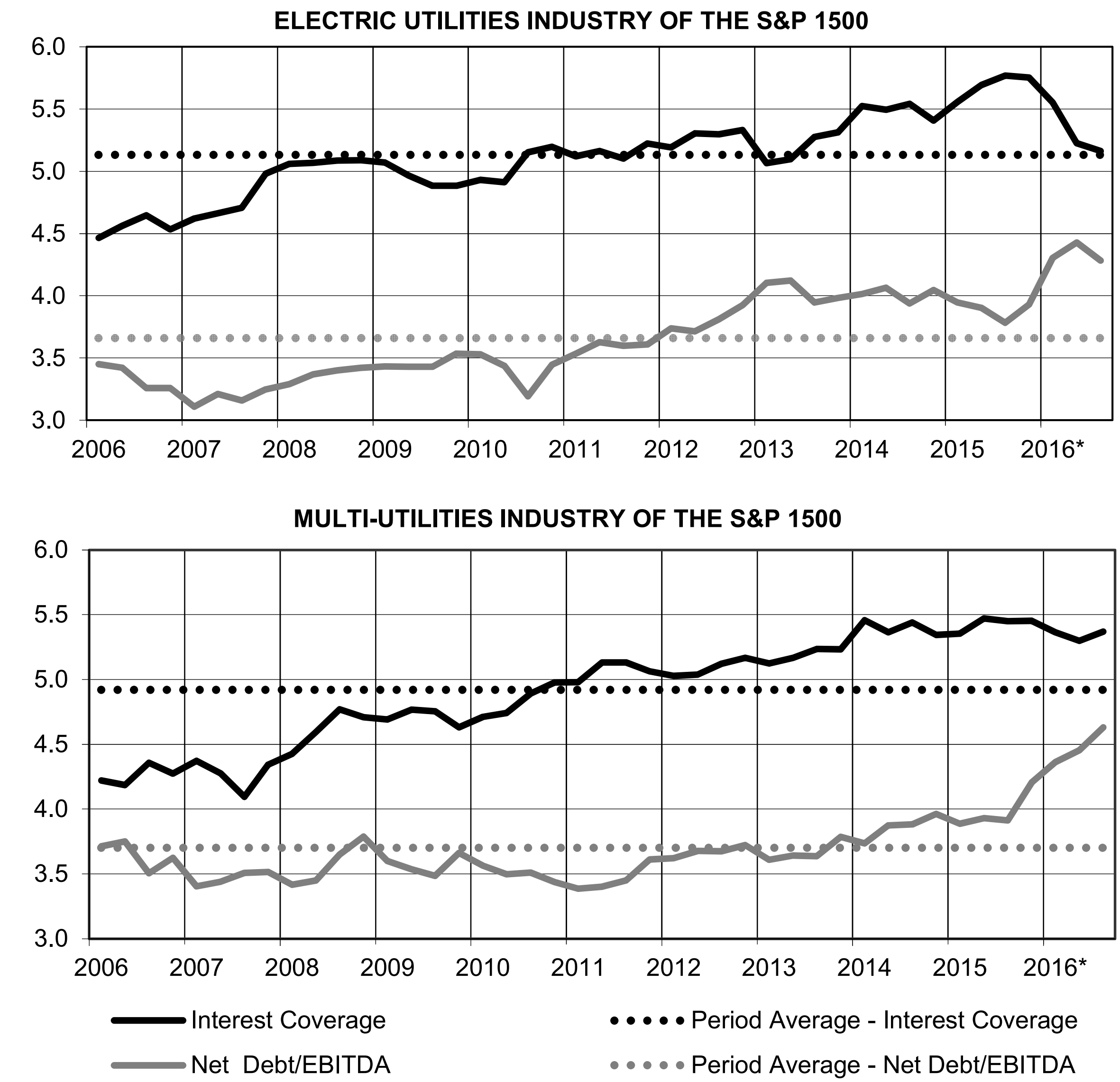
Source: S&P Capital IQ.

◆ Ratios below 47% are not likely to last long, in CFRA's view. As debt ratios strengthen, we think companies will use cash flows to boost share repurchases. In general, the electric utilities industry maintains relatively high debt-to-capitalization ratios when compared with other industries, due to the industry's ability to generate solid and steady cash flows. Likewise, we think that prolonged ratios of more than 50% are unlikely, as utilities can reduce growth through capital spending and share repurchases.

Debt Maintenance

◆ EBITDA-to-interest expense (interest coverage) ratios for electric utilities strengthened steadily over the past 10 years. Predominantly rising EBITDA and relatively steady interest expense levels benefited the interest coverage ratio over this period. With heavy capital spending and recent pressure on EBITDA, interest coverage for electric utilities slipped in recent quarters, dropping to 5.2x in the third quarter of 2016 from 5.8x in the third quarter of 2015.

DEBT MAINTENANCE
(last four quarters, in multiples)



*Data through third quarter.

Source: S&P Capital IQ.

◆ While strong interest coverage levels slipped only recently, net debt-to-EBITDA levels have generally weakened since 2010, with debt levels climbing higher due to capital spending. Net debt-to-EBITDA levels for electric utilities rose at a faster pace to 4.3x in the third quarter of 2016 from 3.8x in the prior-year period.

◆ Multi-utilities interest coverage and net debt-to-EBITDA levels generally track electric utilities. Interest coverage levels recently fell from 5.5x in the second quarter of 2015 to 5.3x in the second quarter of 2016, before rising slightly to 5.4x in the third quarter. Due to higher debt levels, net debt-to-EBITDA levels rose at a faster pace to 4.6x in the third quarter of 2016, from 3.9x in the prior-year period.

◆ With higher capital spending levels anticipated, CFRA thinks that interest coverage and net debt-to-EBITDA levels will continue to weaken slowly for both electric utilities and multi-utilities. We also see unfavorable weather putting pressure on EBITDA for 2017, after hotter-than-normal summers in 2015 and 2016.

Industry Valuation

P/E Ratios

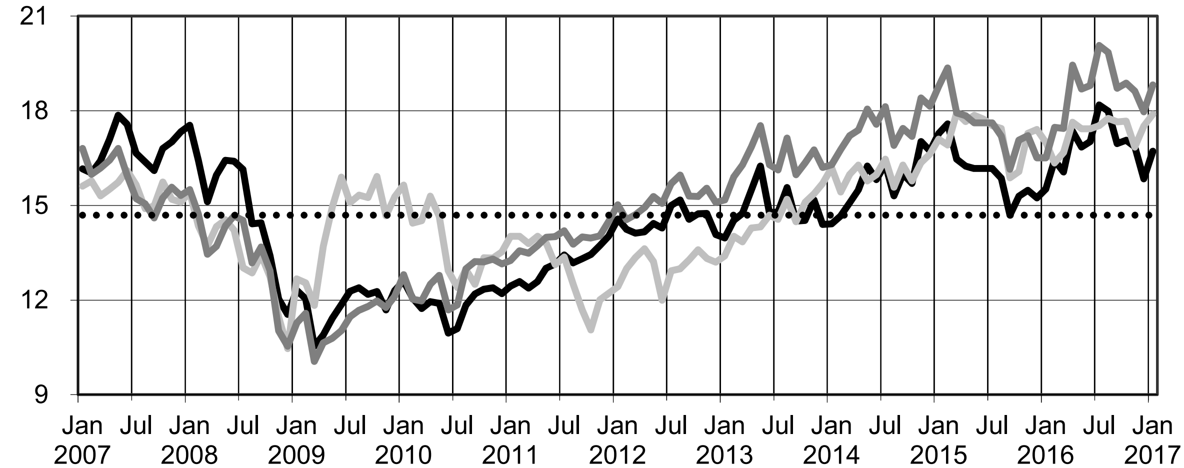
◆ The aggregate value-weighted per share forward price-to-earnings (P/E) ratio has risen steadily since March 2009. Following the recession, prices of electric utilities stocks recovered over time as earnings per share (EPS) and market sentiment improved. In 2015, prices of electric utilities stocks fell early in the year on the threat of higher interest rates, but recovered with improving economic indicators and continued their upward trajectory until July 2016, when shares dipped prior to the election.

◆ Since 2009, the multi-utilities industry has outperformed electric utilities, helped by higher exposure to natural gas and other businesses. Electric utilities stocks have been pressured due to concerns over the Clean Power Plan (CPP) and relatively low capacity and power prices. But even with the likely scrapping of the CPP under the new Trump administration, CFRA thinks that some utilities will still have to continue investing in renewable assets to meet state mandates, leading to an increasing rate base. We see utilities with merchant coal and nuclear plants facing near-term pressure from low natural gas prices.

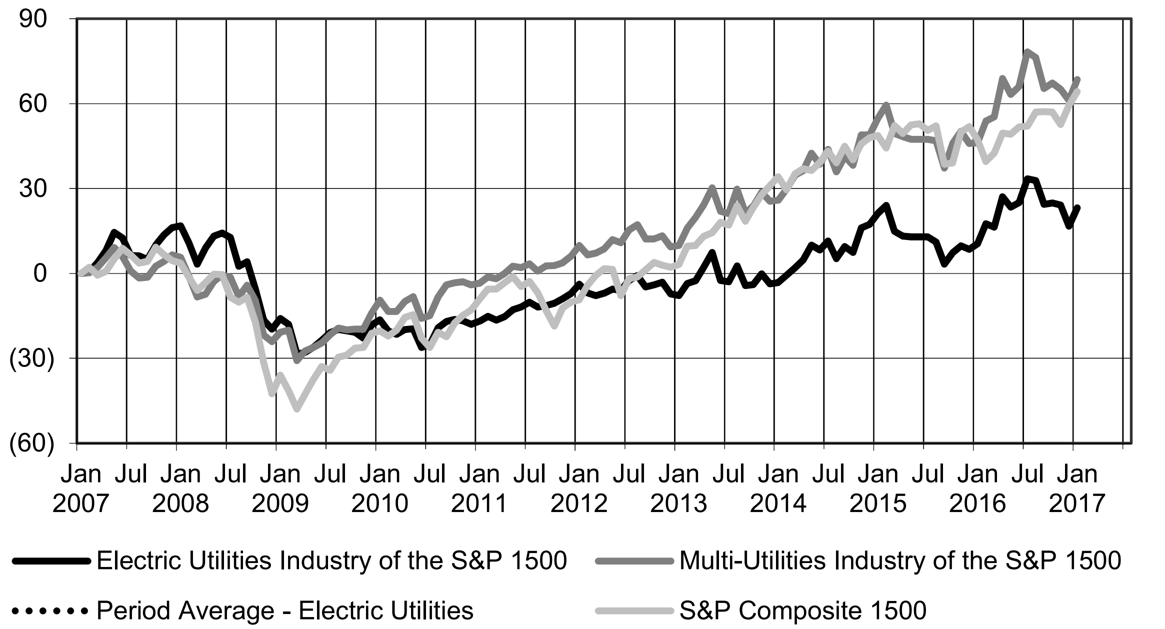
◆ From December 30, 2006 through December 30, 2016, the S&P 1500 multi-utilities total return index widely outperformed both the S&P 1500 electric utilities and the S&P 1500 total return indices, with a compound annual growth rate (CAGR) of 10.4%, compared with 7.9% for the electric utilities industry, 8.7% for the utilities sector, and 7.9% for the S&P 1500. The total return indices assume that dividends are reinvested into each index. During the five years ended January 19, 2017, the total return index CAGR was 14.0% for multi-utilities, 10.3% for electric utilities, 11.7% for the utilities sector, and 14.0% for the S&P 1500.

◆ As of early 2017, CFRA thinks that forward P/E ratios for electric utilities and multi-utilities are relatively high given somewhat slow economic growth, expected pressure on EPS from unfavorable weather, and continued pressure from low power prices.

FORWARD PRICE-TO-EARNINGS RATIO
(in multiples, monthly forward)



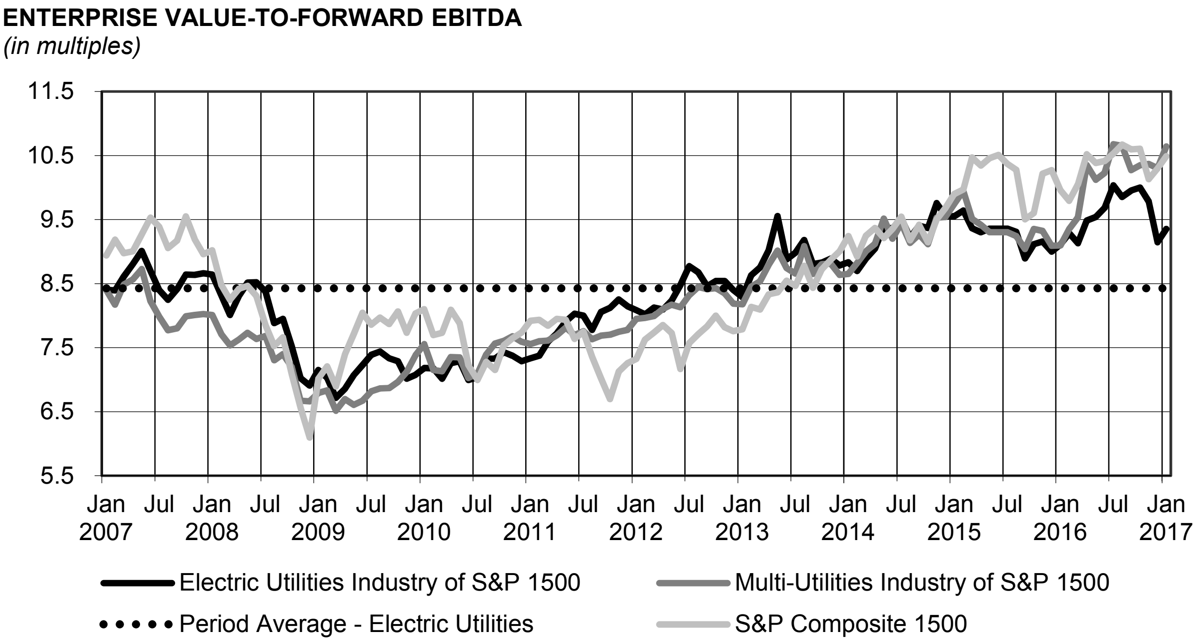
INDEX RELATIVE PRICE PERFORMANCE
(Index value, January 1, 2007 = 100)



Source: S&P Capital IQ.

TEV/Forward EBITDA

◆ The aggregate value-weighted per share total enterprise value (TEV)-to-EBITDA ratio in both the electric utilities and multi-utilities industries has also risen since 2009 for many of the reasons mentioned above. CFRA thinks the ratio for the multi-utilities industry is relatively high (having risen to more than 10x since April 2016), given the risks to earnings and interest rates. However, the ratio for the electric utilities industry, while still high, fell from 10.0x in July 2016 to 9.4x in January 2017. This ratio has room to fall further, in our view, given the risks mentioned.



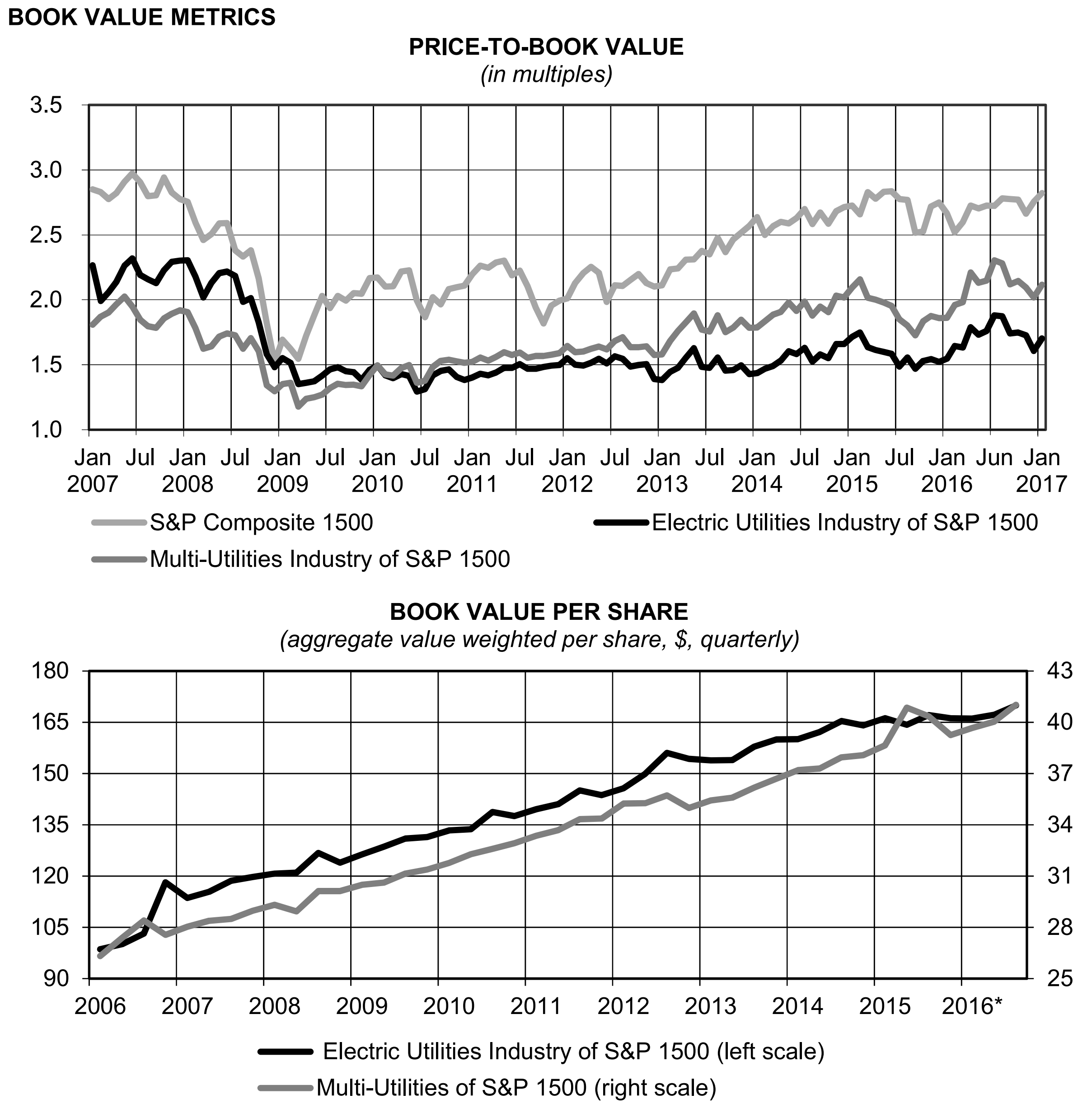
Source: S&P Capital IQ.

Price-To-Book Ratio

◆ Although not commonly used to value electric utilities, price-to-book value is still important to monitor, as it can provide a reality check when evaluating other metrics. While the S&P 1500's price-to-book value has climbed steadily back to pre-recession levels, the ratio for the electric utilities industry has only risen above the 1.5x level since October 2015. The ratio for multi-utilities has grown steadily since 2009.

Book Value per Share

◆ Since the first quarter of 2006, the aggregate value-weighted book value per share has steadily increased at a CAGR of 5.3% for electric utilities and 4.3% for multi-utilities. Strong industry profitability and cash flows are helping drive the increase in common equity. CFRA sees book value per share continuing its steady climb over time as the electric utilities industry increases its earnings.

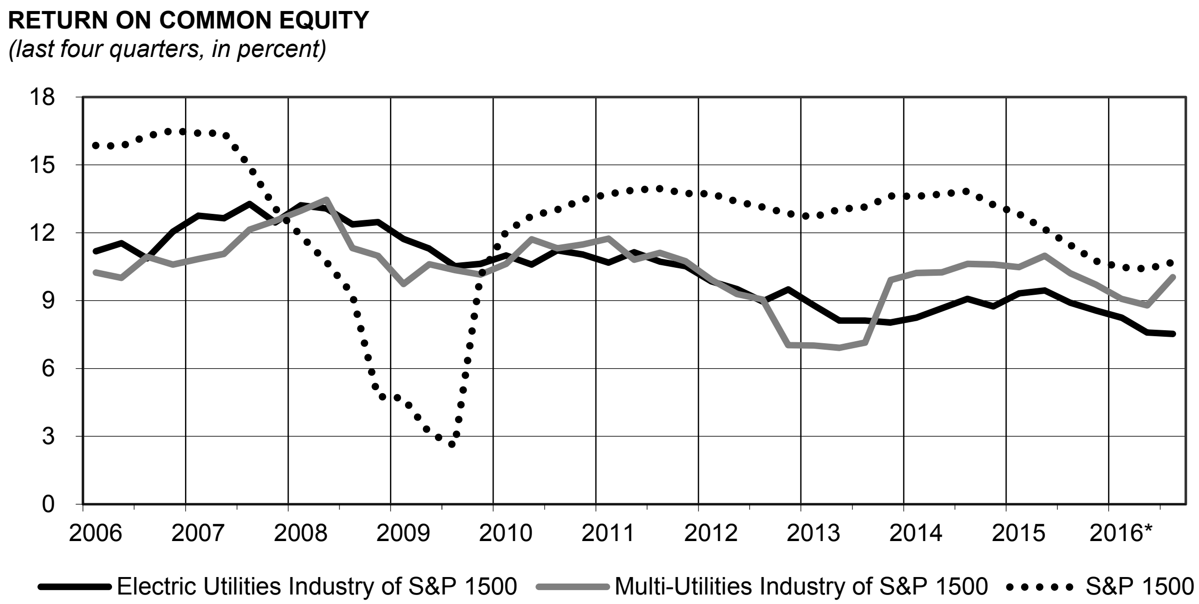


*Data through third quarter.

Source: S&P Capital IQ.

Return on Equity

◆ Return on equity (ROE) for the electric utilities industry has fallen since 2008. CFRA thinks that falling debt-to-capitalization ratios have hurt ROE, and that falling allowed ROEs in subsidiary rate cases over the past five years have also had an adverse effect. (Allowed ROEs are targets set by regulators to provide targets for utility earnings—see the "How to Analyze a Company in This Industry" section.) Some companies have divested their riskier (albeit higher-return) businesses, and this has also put downward pressure on ROEs.



*Data represents last four quarters ending in the third quarter.

Source: S&P Capital IQ.

◆ ROEs for the electric utilities industry will likely remain somewhat stagnant in the 8%–9% range for the next few years, given pressure from unfavorable weather. However, over the long term, as interest rates rise, CFRA thinks regulators will have to increase allowed ROEs for the regulated subsidiaries, creating a boost for industry returns.

INDUSTRY TRENDS

Competitive Environment

Investor-owned, cooperative, municipal, state, and federal utilities, as well as power-generating companies that are not classified as utilities constitute the US electric power industry as defined by the Edison Electric Institute (EEI), the association of US investor-owned electric companies. As this definition includes independent power producers and non-publicly traded companies, it is slightly broader than the electric utilities industry defined by CFRA. Investor-owned utilities provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly and indirectly employ more than one million workers, according to the EEI.

The market capitalization of investor-owned utilities totaled $577 billion (for 46 companies) at the end of 2015 (latest available), down 9% from $632 billion at the end of 2014 and $504 billion at the end of 2013, according to EEI's industry data.

Major changes have been occurring in the industry. Historically, the regulated investor-owned utilities had exclusive franchises to provide vertically integrated electric services to retail customers—usually within a given state, in contiguous areas spanning one or more states, or both. However, the monopolistic, tightly regulated utilities created under trust-busting legislation more than 60 years ago have become increasingly exposed to competition, particularly in the generation and wholesale power markets, due to changes brought about by the National Energy Policy Act (NEPA) of 1992. (For details, see the "How the Industry Operates" section of this *Survey*.)

Meanwhile, multi-utilities companies are comprised of both electric utilities and gas utilities. Several multi-utilities have interstate natural gas pipeline businesses, which CFRA sees benefiting from recent shale drilling activities. In addition, many utilities in the gas-rich Marcellus Shale are completing new gathering and transportation pipeline projects, adding to earnings growth.

In 2015, gas utilities comprised only 23.2% of the total revenues of the S&P 1500 multi-utilities industry. Hence, the performance of the multi-utilities industry is more tied to electric utilities.

Operating Environment

EPA's Pollution Rules Challenge the Industry

On June 23, 2014, the Supreme Court ruled that the US Environmental Protection Agency (EPA) can require greenhouse gas (GHG) controls on power plants and other fixed sources of pollution. Currently, EPA regulations require power plants to obtain permits and adopt GHG controls when modifying an existing facility or when building a new one. Justice Antonin Scalia said that the ruling allowed the agency to regulate facilities responsible for 83% of GHG emissions from stationary pollution sources. However, most of the 189 GHG permits issued will not be undone by the ruling, according to the EPA.

With a goal of combating climate change and improving public health, the EPA finalized the Clean Power Plan (CPP) Rule on August 3, 2015 to cut carbon pollution from existing power plants, which are said to be the largest stationary source of carbon pollution in the US. While coal plant retirements will continue and utilities will likely switch some of that coal-fired generation to cleaner-burning natural gas, the costs will likely be borne by the consumer, making the new proposals manageable for utilities, according to analysis by CFRA.

For new and reconstructed natural gas plants, the emission limit is 1,000 pounds of carbon dioxide per megawatt-hour on a gross-output basis (lb CO2/MWh-gross)—applicable to all sizes of base load units. For new coal-fired power plants, gross emission should not be more than 1,400 lb CO2/MWh-gross. This is less stringent than the proposed standard of 1,100 CO2/MW gross, according to the EPA. The EPA added that the final standard is achievable by new fossil fuel-fired steam generating units for all fuel types. This reflects information and comments with regard to the cost of implementing carbon capture and storage (CCS) on a new unit.

The EPA is not setting a standard for modified natural gas power plants as of its final ruling on August 3, 2015. As for modified coal-fired power plants, EPA determined that the "Best System of Emission Reduction" for modified units is based on each unit's best potential performance. The agency is not setting a standard for units that make smaller modifications A unit that has larger modifications, however, will be required to meet a standard consistent with its best historical annual performance from 2002 to the time of modification.

In the event that stringent carbon emissions regulations are put into place, CFRA thinks the additional costs imposed by various regulations on utilities that burn coal will translate into higher prices paid by retail power customers. Costs to generate electricity will likely go up in the affected utility's service area. However, utilities will likely benefit in the long run as they invest in new power plants or emissions control equipment, because these investments (and the potential purchases of emissions credits under the CPP, if upheld by the courts) will increase their rate base or recoverable expenses. As the rate base rises, utilities will seek rate relief from their regulators—leading to higher rates and earnings per share (EPS).

EPA Rules and Policies in Peril Under Trump

In 2016, the EPA announced that through the CPP, it will work closely with states and stakeholders to help create strong plans to reduce carbon pollution. The agency said it is confident that the CPP will stand the test of time, as the Supreme Court has ruled three times that the EPA has not only the authority but the obligation to limit harmful carbon pollution under the Clean Air Act.

In addition, the EPA reported that the Paris Agreement and the CPP are helping to mobilize private capital worldwide toward low-carbon investments. In December 2015, the US was one of the 195 countries to sign the landmark Paris Agreement, an international climate change pact that requires the signatories to take action to lower carbon emissions. Meanwhile, rules such as the CPP show that working toward a low-carbon future is inevitable, and that the market will reward those who develop low-carbon technologies and make their assets resistant to climate impacts. This is why companies such as Walmart, AT&T, Facebook, and Coca-Cola are acknowledging that climate impacts threaten their operations, while investing in a low-carbon future is an unprecedented business opportunity, according to the EPA.

However, petitions challenging the CPP Rule have been filed in the DC Circuit since it was published in the Federal Register on October 23, 2015. The parties that filed petitions against the CPP include 27 states (West Virginia and Texas spearheaded a coalition of 24 states in filing the lead case, while Oklahoma, North Dakota, and Mississippi filed their own petitions), three labor unions, a number of rural electric cooperatives, and more than two dozen industry and trade groups, among others. In addition, various Members of Congress filed briefs for and against the litigation: 34 current Senators and 171 current Representatives in the 114th Congress filed a brief opposing the CPP, while 164 former and current Representatives and 44 former and current Senators filed a brief in support of the CPP.

On January 21, 2016, the DC Circuit panel comprised of three judges issued an order denying the motions to stay the CPP (pause its legal effect) for the course of the litigation. The panel also ordered a briefing on all issues to be completed in April 2016; an oral argument before the panel was set for June 2, 2016. However, in late January 2016, various state and industry parties submitted applications to the Supreme Court to stay the CPP; EPA and others provided response briefs in opposition to the applications, as requested by the court.

On February 9, 2016, the Supreme Court issued orders to stay the CPP while it undergoes judicial review. The appeals court conducted an en banc hearing on the case on September 27, 2016.

The election of Donald Trump as president will likely put the CPP in jeopardy. During his campaign, Trump vowed to diminish the EPA's role and to reverse the CPP. In December 2016, shortly after his election, he nominated Scott Pruitt, Oklahoma's attorney general and one of the complainants in the lawsuits against the CPP, as the new head of the EPA. In the same month, attorneys general and officers from 24 states sent a letter urging Trump to strike down the CPP on the first day of his term as president. In response to that letter, attorneys general from 14 states and five other officials requested the continued support of the CPP, warning that scrapping the policy would lead to more litigation.

Trump was also critical of the Paris Agreement, vowing during his campaign to end US participation in the deal. However, after the election, he said he has an open mind about the deal. Nevertheless, one of Trump's former advisers claimed that the president is bent on withdrawing the US from the agreement, despite potential opposition from Rex Tillerson, the new secretary of state, according to a report from *Bloomberg News* in January 2017.

CFRA thinks that Trump's stance on these issues would ultimately benefit electric utilities and multi-utilities in the long-term. While the absence of the CPP is likely to lead to lower capital spending levels, thus reducing future rate increases, we project that the absence is likely to lead to higher economic growth over time, especially in manufacturing.

M&A Spree in the Industry

Merger and acquisition (M&A) activity in the electric utilities industry picked up pace in the past two years, primarily led by electric utilities companies that are either consolidating or buying natural gas-related assets.

In May 2016, Great Plains Energy Inc. entered into a transaction to acquire Westar Energy Inc. in a $12.2 billion deal. In July 2016, NextEra Energy Inc. agreed to buy the bankrupt Energy Future Holdings Corp. in a deal valued at $18.7 billion. NextEra is also proposing to buy a 20% stake in Oncor Electric Delivery (in which Energy Future Holdings has an 80% stake) from Texas Transmission Holdings Corp. in a $2.4 billion deal. Meanwhile, Southern Co. bought natural gas company AGL Resources for $12.0 billion in July 2016 and a 50% stake in Southern Natural Gas Co. LLC for $2.7 billion in September 2016.

Electric utilities assets and companies were also sold in the past year. In October 2016, ITC Holdings Corp. completed its $11.5 billion sale to Canadian company Fortis Inc., which then sold about 20% of ITC to Singaporean investor GIC Pte. Ltd. for $1.2 billion. In January 2017, multi-utility company Liberty Utilities Co. bought Empire District Electric Co. for $2.4 billion, while American Electric Power Co. Inc. sold four power plants to Blackstone Group LP and ArcLight Capital Partners LLC in a $2.2 billion transaction.

Multi-utilities companies with electric holdings have also been involved in M&A deals in recent years. WEC Energy Group Inc. bought Integrys Holding Inc., in a $9.1 billion deal closed in June

2015, while Canadian electric utility company Emera Inc. completed its $10.4 billion purchase of TECO Energy Inc. in July 2016. Dominion Resources Inc. acquired natural gas company Questar for $6.1 billion in September 2016.

The acquisitions of gas utilities by electric utilities (*i.e.,* Duke Energy, Southern Co., and Emera) or by multi-utilities (*i.e.,* WEC and Dominion Resources) were likely driven by a perceived need to increase exposure to natural gas after the EPA released the final version of the CPP in August 2015. However, on February 2016 the US Supreme Court halted the implementation of the CPP pending judicial review. Given the expected removal of the CPP by the new administration, there is less pressure for electric and multi-utility acquisitions of gas utilities, in CFRA's view. However, further industry consolidation will likely occur as utilities continue to pursue growth through merger synergies. We expect to see increased activity if relatively lofty utilities stock prices start to decline.

Wind Power, Solar, and Other Generation Additions

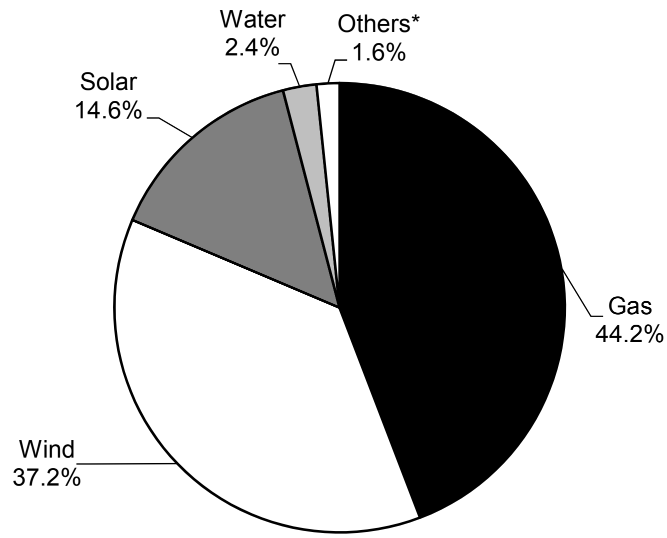
Wind and solar generation capacity have low rates of capacity utilization—only one-third to one-fifth as much as fossil fuel technologies, according to *Public Utilities Fortnightly*, a trade publication. Because of this, three to five times as many megawatts of renewables capacity must be installed, compared with the megawatts of fossil fuel capacity being replaced, to produce equivalent megawatt-hours of electrical energy.

Over the past decade, the electric utilities industry did not build many coal plants in the US. Most of the new power plant capacity additions came from wind (65,207 MW) and natural gas (45,119 MW), according to data available at SNL, a source of data for the utilities sector and a division of S&P Global. Solar additions of 14,222 MW were a distant third, but more solar (7,433 MW) was added compared with gas (7,299 MW) over the past two years, according to SNL.

For new coal plants to be competitive, natural gas prices must increase beyond $7 per million British thermal unit (MMBtu). However, the US Energy Information Administration (EIA) projects in its "Annual Energy Outlook 2017" (AEO2017) report (released in January 2017) that natural gas prices will be about $5/MMBtu between 2030 and 2040. Hence, the EIA expects coal capacities to be retired and virtually no new coal plants to be built, with or without CPP, through 2040. (To comply with the CPP, natural gas can be used to replace coal plants.)

Aside from the decline in coal capacity, petroleum capacity is also expected to decline in the coming years. Between 2015 and 2025, petroleum capacity is expected to decline at a 0.5% compound annual growth rate (CAGR) from 32,507 MW to 30,869 MW, according SNL projections. Likewise, the projections indicate that coal capacity will decline at a 0.8% CAGR from 274,671 MW to 252,728 MW during the same period. The expected decline in coal and nuclear capacity will likely contribute to the market's increased reliance on natural gas, solar, and wind. SNL expects natural gas capacity to grow at a 2.0% 10-year CAGR from 447,848 MW in 2015 to 543,318 MW in 2025. SNL sees wind capacity growing at a 6.5% CAGR from 74,232 MW to 139,167 MW, and predicts solar capacity growing at a 10.5% CAGR from 14,556 MW to 39,349 MW during the same period. Meanwhile, nuclear capacity is projected to grow at a 0.2% CAGR from 98,704 MW to 100,456 MW.

POWER PLANTS UNDER CONSTRUCTION AND IN DEVELOPMENT BY PRIMARY FUEL TYPE
(early and advanced development stage, units in service for 2017)



*Others include:

Biomass	0.7%
Other Nonrenewable	0.6%
Geothermal	0.2%
Oil	0.1%

TOTAL: 40,198 MW

Source: SNL Financial.

US POWER PLANT CAPACITY PROJECTIONS
(all regions, in megawatts, arranged by 2015 capacity)

Fuel	2015	SHARE(%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	SHARE(%)	10-YEAR CAGR *(in percent)*	TOTAL CHANGE 2015-2025
Natural Gas	447,848	42.0	454,264	468,781	495,890	520,239	531,546	538,987	540,642	541,218	542,118	543,318	43.7	2.0	95,470
Coal	274,671	25.7	266,762	261,426	258,345	257,961	256,486	256,348	255,634	254,952	254,348	252,728	20.3	(0.8)	(21,942)
Water	102,244	9.6	102,457	103,786	104,532	105,851	107,045	109,659	110,200	110,647	110,994	110,992	8.9	0.8	8,748
Uranium	98,704	9.2	99,440	98,587	98,605	99,996	102,223	102,583	102,583	102,583	102,541	100,456	8.1	0.2	1,752
Wind	74,232	7.0	81,516	96,486	112,875	124,220	133,888	135,983	137,602	138,402	138,402	139,167	11.2	6.5	64,935
Petroleum Products	32,507	3.0	31,608	31,023	31,023	31,017	30,869	30,869	30,869	30,869	30,869	30,869	2.5	(0.5)	(1,639)
Biomass	14,857	1.4	14,717	14,861	15,293	15,492	15,493	15,493	15,493	15,493	15,493	15,493	1.2	0.4	637
Solar	14,556	1.4	21,817	27,696	32,486	34,142	36,971	36,971	36,971	36,971	36,971	39,349	3.2	10.5	24,793
Other Fuel	5,218	0.5	5,119	5,344	5,512	5,582	6,236	6,421	6,421	6,421	6,421	6,421	0.5	2.1	1,203
Geothermal	2,580	0.2	2,583	2,657	2,779	2,914	3,501	3,571	3,621	3,621	3,621	3,621	0.3	3.4	1,041
TOTAL	1,067,417		1,080,283	1,110,646	1,157,339	1,197,414	1,224,259	1,236,885	1,240,037	1,241,178	1,241,779	1,242,414		1.5	174,997

Note: Future capacity is based on actual, planned or under construction projects, and, not based on any projections of unreported new developments or retirements.
Source: SNL Financial.

Expected Power Plant Additions in the Next Few Years

Electricity demand growth remained relatively low at 0.5% from 2000 to 2015, and it is expected to grow 0.8% on average between 2016 and 2050, according to AEO2017. This level of anticipated growth in electricity demand can be attributed to slowing population growth, improving efficiency of appliances and equipment, near market saturation of key electricity-using appliances, and a shift toward less energy-intensive industries.

Over the past decade, CO2 emissions declined as a result of shifts toward less carbon-intensive generation sources, low natural gas prices, federal tax credits for renewables, and state-level renewable portfolio standards. CFRA thinks natural gas-fueled generation capacity will continue to rise as EPA regulations surrounding sulfur and nitrogen emissions encourage companies to switch out of coal. We also think the likely scrapping of the CPP will lead to prolonged lives for existing coal plants and reduce the need for new generation.

The percentage of renewable energy contribution to total power generation is expected to increase from 14.3% in 2016 to 28.0% in 2050, and natural gas from 33.6% to 40.0%, while the share of coal and nuclear is expected to decline from 31.2% and 18.6% to 18.7% and 13.0%, respectively, in the same period, according to EIA. In terms of renewable electricity generation, the share of solar power is expected to increase from 6.0% in 2016 to 22.3% in 2050, and wind from 39.5% to 45.7%, while the share of hydroelectric, geothermal, and biomass power is expected to drop from 50.9% in 2016 to 30.2% in 2050.

Market Forces and New Pollution Regulations Lead to Coal Retirements

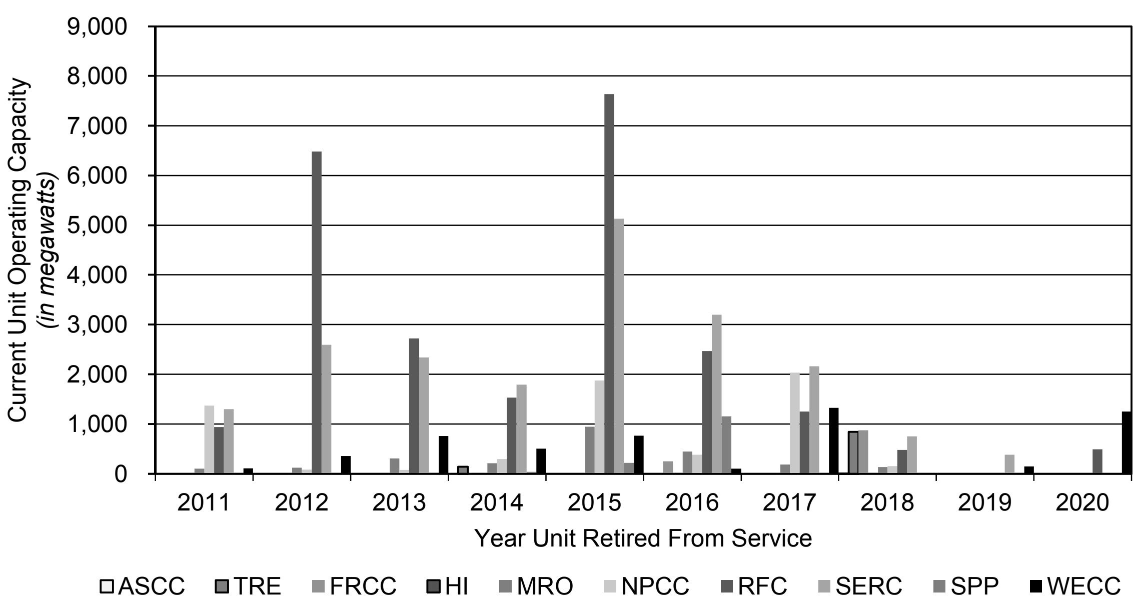
Recent trends in the electric utilities industry—such as lower natural gas prices, slower growth of electric demand, and environmental regulations—have resulted in declining revenues and increased operating costs for coal plants. The decline in natural gas prices since 2008 has driven down electricity prices and payments received by generators for the electricity they produce. Lower natural gas prices also strengthen the competitiveness of natural gas combined-cycle (NGCC) power plants, lowering the cost of generating electricity from an NGCC plant to below the cost of its nearby coal-fired plant. As a result, that coal plant is operated less often, thus earning less revenue and making it a candidate for retirement.

The annual average coal price to electric power plants dropped from $2.39/MMBtu in 2011 to $2.23/MMBtu in 2015, according to EIA data. As of January 2017, the EIA expects coal price to increase to an average $2.13/MMBtu in 2016 and $2.18/MMBtu in 2017.

The implementation of the EPA's Mercury and Air Toxics Standards (MATS) and low natural gas prices have attributed to coal-fired generating capacity in the US dropping from 299 gigawatts (GW) in 2014 to 274 GW in 2015 and 262 GW in 2016. The share of coal-fired generation fell from 39% in 2014 to 31% in 2016. Operators invested at least $6.1 billion in compliance to MATS and other environmental regulations from 2014 to 2016, according to the EIA.

The EIA's AEO2017 projects that 34.7 GW of coal plant capacity will be retired between 2017 and 2020, and an additional 65.8 GW of coal-fired capacity is expected to be retired thereafter.

COAL RETIREMENT SUMMARY



Source: SNL Financial.

Some Nuclear Facilities Retired

In recent years, the industry has seen a number of nuclear plant retirements. In 2013, there were three major retirements. Southern California Edison (SCE), a subsidiary of Edison International, announced its decision to permanently retire Units 2 and 3 of its 78.2%-owned San Onofre Nuclear Generating Station (SONGS), which had a combined generating capacity of 2,150 MW. In the same year, Dominion Resources Inc., one of the largest electric and gas holding companies in the US, retired its Kewaunee Power Station in Wisconsin, which had a generating capacity of 556 MW. The company's decision to retire the plant, which was licensed to operate through 2033, was an economic one. Finally, Duke Energy Corp., the largest electric power company in the US, announced that it would retire its Crystal River 3 Nuclear Generating Plant in Florida, which it had acquired when it merged with Progress Energy Inc. in July 2012. Due to uncertainties related to the costs and timing of the needed repairs, the company decided to retire the plant.

In 2014, Entergy Corp. closed and decommissioned its Vermont Yankee Nuclear Power Station in Vernon, marking the end of 42 years of operation. The station said that sustained low power prices, high-cost structure, and wholesale electricity market design flaws influenced the decision. Exelon Corp. is expected to retire its Oyster Creek Generating Station in New Jersey by the end of 2019; the plant will have achieved 50 years of operation by the date of its final retirement.

In 2015, Entergy announced plans to retire plants. Entergy Corp. is expected to close its Pilgrim nuclear power station in Massachusetts no later than June 1, 2019, citing poor market conditions, reduced revenues, and increased operational costs as the reason for the decision. In November 2015, the company announced that it is planning to close its single-unit James A. FitzPatrick nuclear power station in the state of New York by late 2016 or early 2017 due to reduced plant revenues, poor market design, and high operational costs. Then in August 2016, Exelon Corp. agreed to assume ownership and management of operations of Entergy's FitzPatrick facility.

In December 2016, Entergy revealed plans to shut down the Palisades nuclear power plant in Michigan on October 1, 2018. In January 2017, the company entered into an agreement with the state of New York to close the two operating units of the Indian Point Energy Center nuclear power plant in April 2020 and April 2021, respectively. In exchange, the state has agreed to drop legal challenges against the plant.

Through July 2016, a series of nuclear plant retirements were announced. On June 2, 2016, Exelon said that it would shut down the Clinton and Quad Cities nuclear plants in June 2017 and June 2018, respectively, due to the lack of progress on the Next Generation Energy Plan legislation. On June 21, 2016, Pacific Gas & Electric Co. proposed to close two reactors at Diablo Canyon in 2024 and 2025 because of the increasing use of renewable energy in California. On October 24, 2016, the Omaha Public Power District (OPPD) shut down the Fort Calhoun nuclear power plant in Nebraska, the fifth US-based nuclear plant to retire in the past five years.

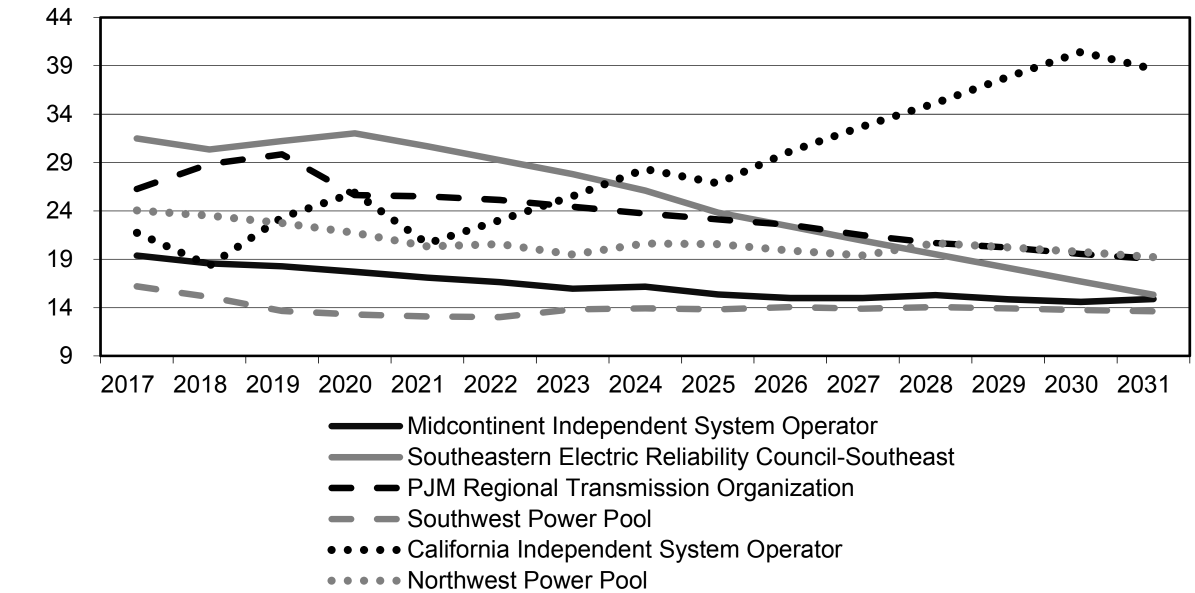
Power Supply/Demand and Reserve Margin Forecasts

Anticipated reserve margins in all assessment areas were expected to meet or exceed corresponding reference margin levels within the next 10 years, according to the "2016 Long-Term Reliability Assessment," published by the North American Electric Reliability Corp. (NERC). However, three of these areas fall below their respective reference margin levels in the six- to 10-year time frame.

In addition, NERC's 10-year forecast CAGR of peak summer and winter electricity demand dropped to the lowest rates on record last year. Growth rates in10-year peak demand and energy forecasts remain flat, mainly due to widespread implementation of energy efficiency and conservation programs, among other things.

Forecasts have shown greater uncertainty regarding some resources amid recent environmental and other regulatory requirements, according to NERC. The advanced retirements of conventional fossil-fired generating units and contributions from an increasing amount of variable generation have compounded this uncertainty.

FORECAST RESERVE MARGIN
(in percent, as of December 31, 2016)



Source: SNL Financial.

CFRA thinks that the reserve margin forecasts are tied to the reduction in overall plant capacity from retiring coal plants and that the declining reserve margins will likely lead to higher power prices for the industry.

New Major Transmission Projects

Electric utilities invest in their systems to provide reliable and economic electric service—addressing system needs, including meeting reliability requirements, modernizing and replacing infrastructure, accommodating new and retiring electricity generation sources, and meeting public policy requirements. The EEI's "Transmission Projects: At A Glance" report in December 2016 showcased the major transmission projects that EEI members have planned for the next 10 years.

The EEI estimates that total transmission investments increased from $20.1 billion in 2015 to $21.5 billion in 2016, adding that investments will likely increase to $22.5 billion in 2017. These transmission investments include providing a reliable electricity service, relieving congestion, facilitating wholesale market competition, supporting a diverse and changing generation portfolio, mitigating damage and limiting customer outages in extreme weather, and deploying advanced monitoring systems and other new technologies designed to ensure a more flexible and resilient grid.

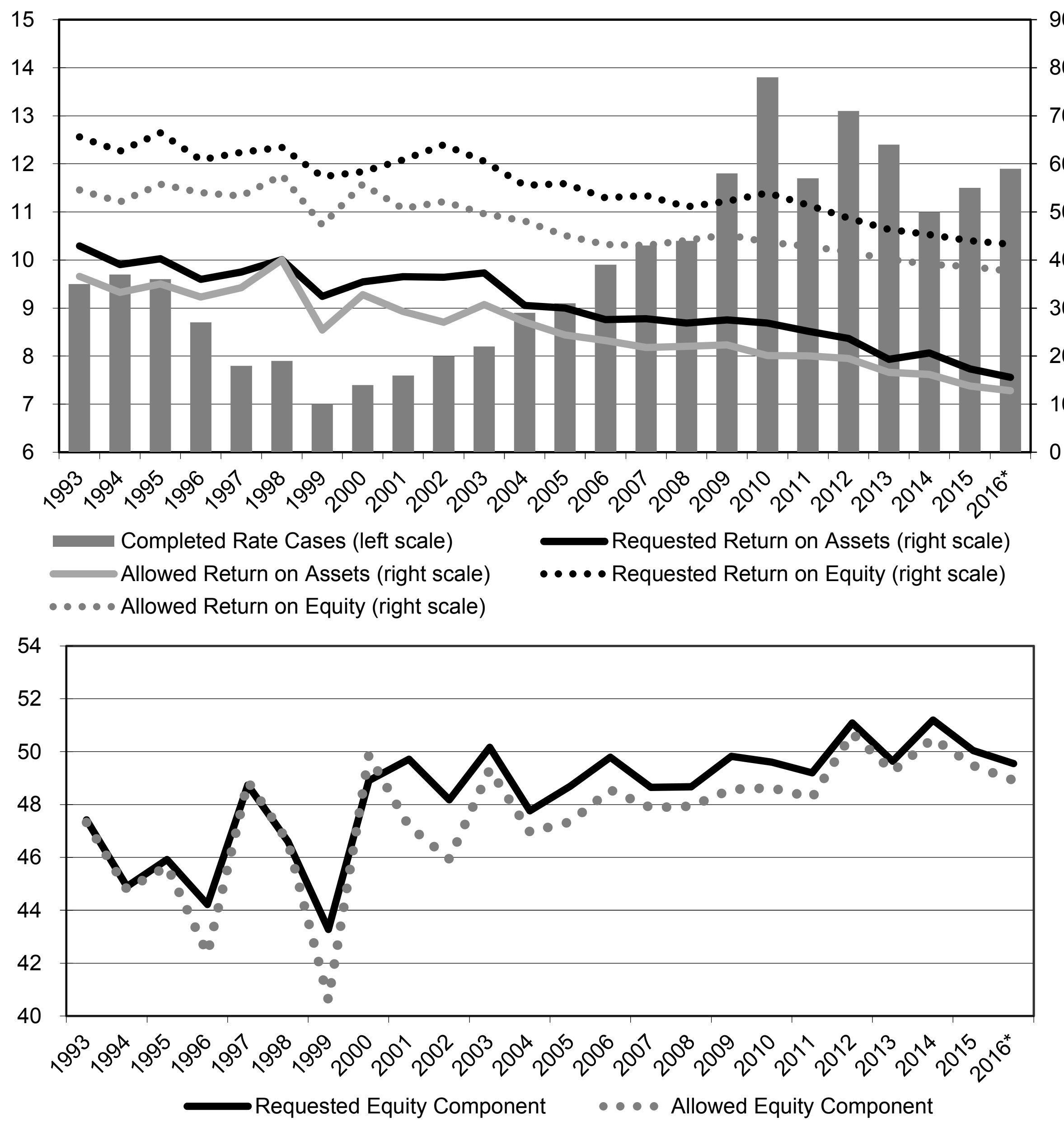
The EEI highlighted more than 150 projects amounting to approximately $41.0 billion in transmission investments through 2019. Most of these investments focus on new large-scale, high-voltage facilities, as well as upgrades and replacement of existing facilities amid the continued retirements of traditional coal-fueled and nuclear power plants, according to the report.

Electric Utilities Rate Cases

In 2015, there were only 55 rate cases completed with an average allowed ROE of 9.9%, allowed return on assets (ROA) of 7.4%, and allowed common equity component of 49.5%, according to SNL. In 2016, 59 cases were completed, with an average allowed ROE of 9.8%, allowed ROA of 7.3%, and allowed common equity component of 48.9%.

RATE CASE METRICS

(values in percent)



*Data through January 17, 2017.

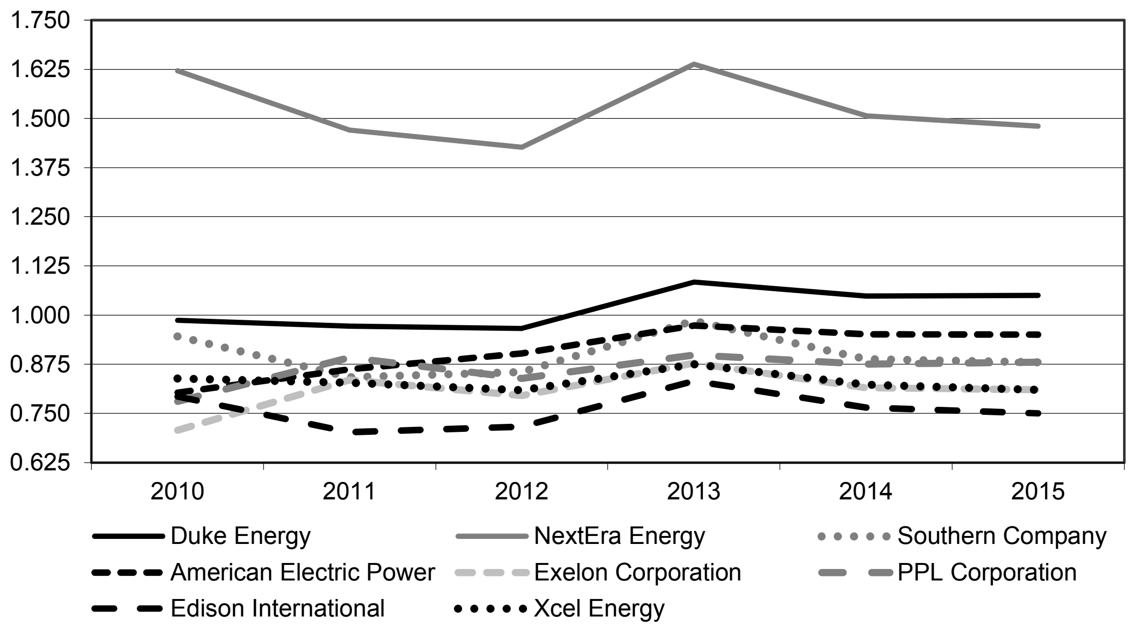
Sources: SNL Financial; S&P Capital IQ.

Top Eight—Pension Funding Status

For many companies, the pension fund is a long-term liability and is not captured on the balance sheet. A pension plan has two elements: the future liabilities (benefit obligations) created by employee service, and the pension fund (plan assets) that companies use for retiree benefit payments. Companies—the pension plan sponsor—contribute to the pension fund, which is invested into bonds, equities, and other assets to meet long-term obligations. Year after year, companies are required to oversee fluctuations in investment returns and actuarial calculations to keep the pension fund accounts from being significantly over- or under-valued. An important number to watch is the funded status of the plan, calculated by subtracting the projected benefit obligation from the fair value of the plan assets.

In 2015 (latest available), four of the top eight companies in the electric utilities industry saw a year-over-year decline in the funded status of their pension plans, while the remaining half had the same multiple as the prior year. From 2010 to 2015, only two firms, Duke Energy and NextEra, had a multiple of more than or equal to 1x, while the other six were underfunded or had multiples of less than 1x, based on SNL data.

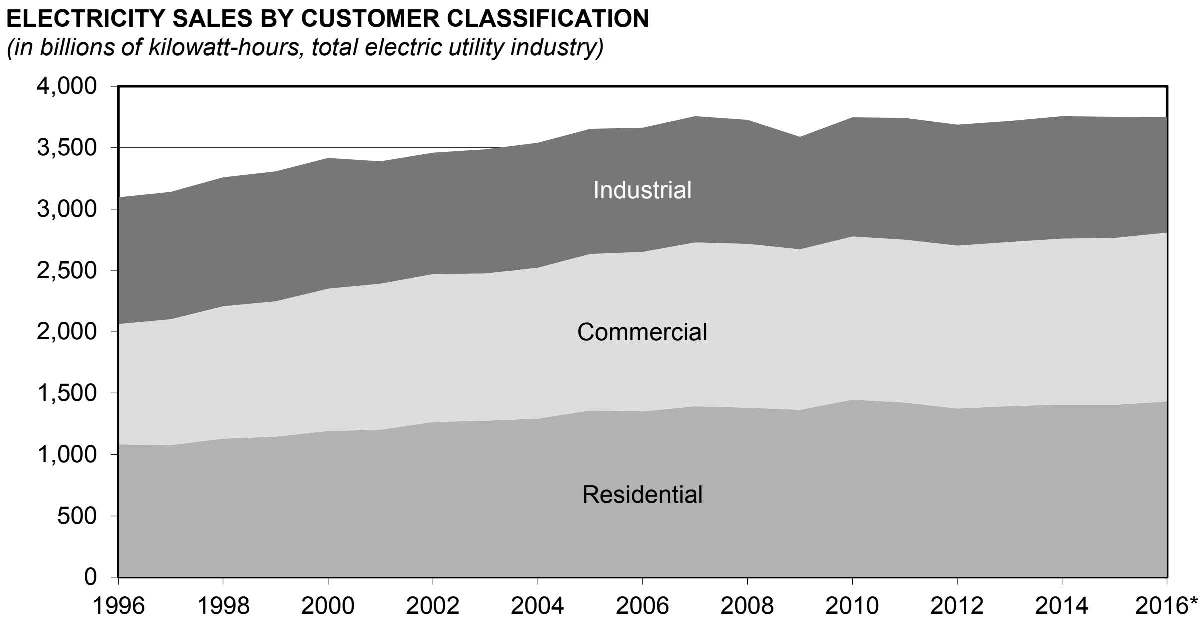
ELECTRIC INDUSTRY PENSION FUNDED STATUS
(pension plan assets fair value-to-pension benefit obligation, in multiples)



Source: SNL Financial.

Electric Utilities Outlook Varies by Customer Segment

Total electricity volumes in 2016 declined 1.3% to 3.7 trillion kWh, whereas revenues reached $381.4 billion, down 2.5% from 2015, according to the EIA.



*Annualized based on January to October data.
Source: Energy Information Administration.

◆ **Residential.** In 2016, electricity sales to residential customers were up 0.2% from the prior year to 1.4 trillion kWh, whereas revenues decreased 0.6% to $176.6 billion, according to the EIA. Although this market has begun to recover, CFRA thinks that the slow rate of new US household formations and the modest growth in the overall population will restrict growth for the foreseeable future. Thus, demand changes will likely remain mostly weather-related.

◆ **Industrial.** The volume of electricity sold to industrial customers reached 936.3 billion kWh in 2015, down 5.1% from 2015, according to EIA reports. This also led to a 7.3% year-over-year decline in revenues. While CFRA expects these sales to continue to grow along with the economy, long-term growth in industrial sales will likely be much more modest than the growth for the residential and commercial segments, reflecting the shift in the US economy from a manufacturing economy to a service economy and the ability of large industrial firms to buy power from competing energy providers.

◆ **Commercial.** The EIA also reported that in 2016, electricity sales to commercial customers totaled 1.4 trillion kWh (down 0.1% from the prior year), while revenues reached $140.9 billion (down 2.7%). Over the next several years, CFRA expects to see increased demand from the commercial segment, with the pace dependent on the strength of the economy.

Regulatory & Legislative Environment

Final FERC Rule for Transmission Facilities

The “not in my backyard” attitudes that have hindered the construction of new transmission facilities was effectively countered by legislation. In any geographic area where transmission capacity constraints or congestion affect consumers, the Department of Energy (DOE) was given the authority to designate a “national interest electric transmission corridor,” after consulting with the appropriate states and regional reliability entities. The Federal Energy Regulatory Commission (FERC) had the authority to issue permits for the construction or modification of transmission facilities in such areas and under specified conditions. Permit holders could acquire the rights-of-way for the project by exercising eminent domain in the federal district court with jurisdiction over the area where the property is located.

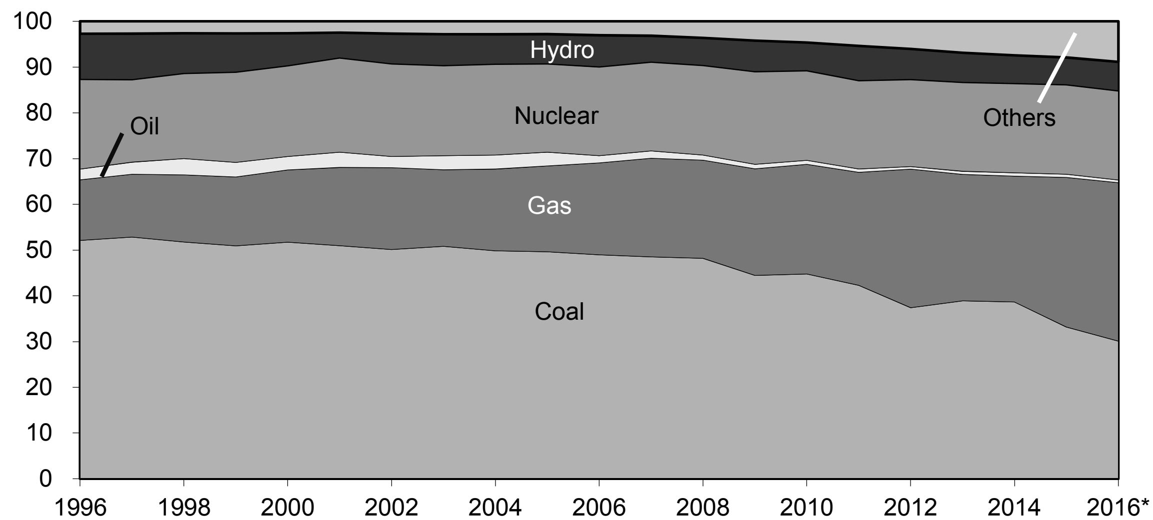
The FERC issued its Final Rule in July 2006, promoting transmission-pricing reforms that were designed to promote needed investment in the US energy infrastructure. The Energy Policy Act (EPAct) of 2005 had directed the FERC to develop incentive-based rate treatments for the interstate transmission of electric power. The Final Rule was intended to implement those incentives, provide regulatory certainty, and ensure that transmission rates remain just and reasonable.

The rate incentives identified in the Final Rule were intended for both traditional utilities and stand-alone transmission companies (known as "transcos"). The incentives include providing an ROE sufficient to attract new investment. This enables the recovery at a rate base of 100% of prudent transmission-related construction work in progress, accelerates the recovery of depreciation expense, enables the recovery of deferred costs and provides a higher rate of ROE for utilities that join transmission organizations. In addition to enhancing the reliability of the national grid, the Final Rule aims to expedite the procedures for the approval of incentives and to facilitate the financing of transmission projects.

HOW THE INDUSTRY OPERATES

Since electricity was first harnessed more than 100 years ago, technological advances have altered the landscape of the electric utilities industry. Nevertheless, the physics of electricity generation has not changed: electricity is produced when a magnet is rotated inside a coil of wire. The spinning of the magnet may be caused by steam (as in coal, oil, and nuclear power plants), by falling water (as in hydroelectric plants), or by hot expanding gases (as in gas turbines and diesel generators).

ELECTRIC GENERATION BY ENERGY SOURCE
(percentage of US total)



*Annualized based on January to October data.

Source: Energy Information Administration.

Electrical energy cannot be stored economically, so it must be generated and instantaneously delivered, based on customer demand. Consequently, a company in the electric utilities industry must own production facilities capable of meeting the maximum demand on its system, as well as transmission and distribution systems that can manage the load. Each utility must also have a reserve margin of extra production capability to allow for maintenance, equipment outages, and unexpected variations in usage.

In general, the electric utilities industry's peak earnings come with the warm weather in the second and third quarters, when customers are running air conditioners. By contrast, cold weather tends to have a marginal impact on earnings; most customers use electricity simply to start their heaters, while fuel (oil or gas) provides the heat. Thus, electric utilities' lowest earnings typically occur in the first and fourth quarters, although actual results may vary by region, and depend on weather conditions and other factors.

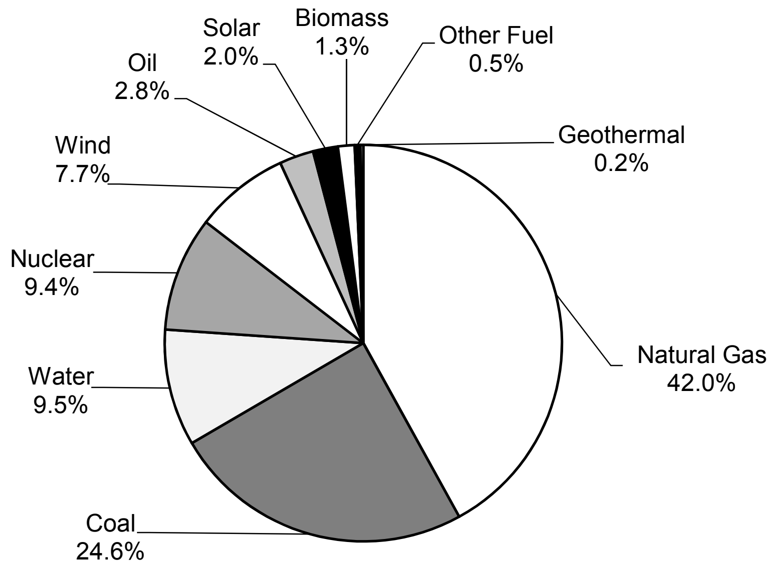
Generating Power

The electric utilities industry relies on various fuel sources to generate electricity. Some utilities also purchase power to meet peak demand.

Fuel Sources

Fuel sources used by the electric utilities industry include coal, natural gas, nuclear power, renewable sources (including hydroelectric and wind), oil, and other gases.

US OPERATING PLANT CAPACITY BY FUEL TYPE
(based on summer capacity, as of January 18, 2017)



Source: SNL Financial.

AVERAGE COST OF FOSSIL FUELS DELIVERED TO STEAM-ELECTRIC UTILITY PLANTS
($ per million Btu consumed)

YEAR	COAL	RESIDUAL OIL*	NATURAL GAS	ALL FOSSIL FUELS†
2016‡	2.13	8.10	2.76	2.43
2015	2.22	10.18	3.26	2.65
2014	2.37	18.72	5.08	3.25
2013	2.34	19.35	4.35	3.09
2012	2.38	21.12	3.45	2.83
2011	2.39	18.46	4.72	3.28
2010	2.27	12.75	5.11	3.25
2009	2.21	9.55	4.82	3.05
2008	2.07	13.46	8.87	4.09
2007	1.77	8.92	7.18	3.22
2006	1.69	7.70	7.06	3.01
2005	1.54	6.84	8.21	3.23
2004	1.36	4.75	5.97	2.48
2003	1.28	4.66	5.43	2.28
2002	1.25	3.63	3.57	1.85

Btu-British thermal unit. *Includes fuel oils No. 4, No. 5, No. 6, and topped crude fuel oil. †The weighted average price for all fossil fuels includes both residual fuel oil and light oil (fuel oil No. 2, kerosene, and jet fuel), as well as small quantities of coke oven gas, refinery gas, and blast furnace gas. ‡Data through October. Source: Energy Information Administration.

◆ **Natural gas.** Last year, natural gas surpassed coal as the most significant fuel source for electricity in the US. In 2016, natural gas accounted for 33.8% of US electricity production, up from 32.7% in the prior year. according to data from the Energy Information Administration (EIA). The sharp rise in recent years was driven by the growth in natural gas reserves, the high level of natural gas production, and the sharp decline in natural gas prices, according to the Edison Electric Institute (EEI).

◆ **Coal.** Coal accounted for 30.4% of US electricity production in 2016, down from 33.2% in the prior year, according to the EIA. Coal's share of total production has been on a general decline since 2007, which in CFRA's view, largely reflects the effects of low natural gas prices and the relative flatness in power demand.

◆ **Nuclear power.** In 2016, nuclear power accounted for 19.7% of US electricity production, compared with 19.6% in 2015, according to the EIA. This fuel's clean air emissions and relatively low cost of production have made it compelling. However, even before the crisis at Fukushima, it was felt that the development of nuclear plants in the US was unlikely to occur quickly, due to the expense associated with new plant construction and the length of time involved in the regulatory approval process. In addition to the increased costs pertaining to the heightened scrutiny of existing nuclear plants in the US, there are costs related to the decommissioning of a plant, which involves reducing radioactivity, disposing of nuclear waste, and dismantling certain machinery. Utilities are required to prefund decommissioning costs over each plant's 40-year operating life. These costs are substantial, generally in the hundreds of millions of dollars.

◆ **Renewable sources.** Renewable generation, including hydroelectric power and solar, accounted for 14.9% of total electricity generation in 2016, up from 13.3% in the prior year. Non-hydro renewable generation, which includes wind, solar, geothermal, and biomass sources of power, accounted for 8.4% of US electricity production in 2016 and 7.2% in 2015.

◆ **Petroleum.** In 2016, power production from petroleum, which includes petroleum liquids and petroleum coke, accounted for 0.6% of total electricity generation, down from 0.7% in the prior year. Electric energy production using petroleum occurs chiefly in the Northeastern and the Southeastern regions of the US.

◆ **Other gases.** Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels, accounted for about 0.3% of US electric power supply from 2015 through 2016.

Purchased Power Fills the Gap

Wholesale wheeling—the buying and selling of power by different utility-related companies—has significantly increased utilities' use of purchased power. Urban utilities in particular, with their high daytime peak loads, have found that purchased power contracts let them meet peak demand and boost their load factors without building additional capacity.

A purchased power contract generally has two components: a capacity charge and an energy charge. The capacity charge is usually considered a rate base item; in other words, it is incorporated into the end-customer's base rates, whether or not the power is used. Energy charges are regarded as fuel costs and are passed along to the end-customer on a dollar-for-dollar basis, according to usage.

Getting Power to the User

A combination of generators is used by a utility to accommodate different levels of demand. Baseload generating units can supply large amounts of power; they ordinarily operate at or near full capacity for long periods. While baseload generating units are the most expensive units to build in terms of capital investment, they are also the most efficient—and thus the most economical, in terms of operating expenses.

In contrast, peaking units are designed to operate exclusively during periods of high demand, and may run for as little as a few hours at a time. These generators—usually oil or gas combustion turbines—are the least costly in terms of capital investment, but they are usually the most expensive to run.

The cycling unit, an intermediate class of generator, runs when demand is above the capacity of the baseload generators but below the level necessary to use the peaking units. In terms of capital investment and operating costs, cycling units normally fall between baseload generators and peaking units.

Transmission and distribution facilities are the arteries through which power is delivered to customers. To transmit electricity effectively over long distances while minimizing power losses, utility companies use high-voltage transmission lines. Although such lines commonly cost considerably more to build than low-voltage wires, they can carry much more power.

Transformers reduce the voltage of electricity as it moves from transmission lines to distribution lines. At a customer's site, meters attached to the distribution lines measure the amount of electricity used during a particular period so that the utility may charge the appropriate sum to each account.

Some electricity-generating plants are members of regional "power pools," which generally are made up of several investor-owned utilities in a geographic area. The participating power plants dispatch electricity to all member utilities from a central control point.

Peak Load and Energy Rates

A utility's customer profile (the proportion of its sales that go to large industrial and wholesale customers versus smaller retail customers) can have a big influence on both its expenditures and its rates. Utilities forecast their peak loads—the average amount of energy required to serve customers at times of greatest usage—based on the average total demand from all customers at peak periods. Peak loads can differ significantly from utility to utility. The loads of some companies are relatively uniform throughout the day, whereas others are heavily concentrated during particular hours.

Capacity and Load Factors

A utility's capacity factor is the relationship between demand and capacity. It is the measure of actual output versus a generator's rated capacity.

Load factor is a related but somewhat different concept: the ratio of actual electric energy consumption during a given time period relative to the consumption that would have occurred if usage had been fully sustained at the peak capacity level. Thus, it measures the variability of load (or demand) over a given time period. A high load factor means that a utility operates near capacity most of the time.

How Rates Are Set

State commissions are responsible for determining utilities' proper rate bases and allowable operating expenses. The rulings of individual states often differ with regard to these determinations. They also differ in allowed accounting treatments for depreciation accruals and investment tax credits. Although rulings are often presumed to be based solely on the public interest, commissions actually seek to provide a balance between investor and consumer interests.

Shareholder risk is a component of a utility's allowed rate of return. To determine risk levels, state utility commissions consider the percentage of common equity versus debt in a utility's capitalization. The higher the equity component, the lower the assumed risk; a lower assumed risk generally results in a lower allowed rate of return. In contrast, shareholders that assume higher risk usually will be allowed a higher potential return.

Utilities that engage in significant cost-cutting tactics, such as work force downsizing and refinancing (both prevalent in recent years), often attempt to delay the next rate review for as long as possible. This strategy lets its investors benefit from the savings until the next rate case.

Consumer Safeguards

Electric utilities companies are required to charge what the regulatory bodies deem "just and reasonable rates" in order to protect consumers against potential pricing abuses while allowing utilities to attract capital and provide adequate service.

Establishing a utility's rates on an individual cost-of-service basis typically involves two steps. The first is to determine the rate level that will cover the utility's operating costs and give it an opportunity to earn a reasonable return on its investment. The utility's required revenue is often referred to as the "revenue requirement" or "cost of service." The second step designs specific rates that will eliminate discrimination against, and unfairness toward, affected classes of customers.

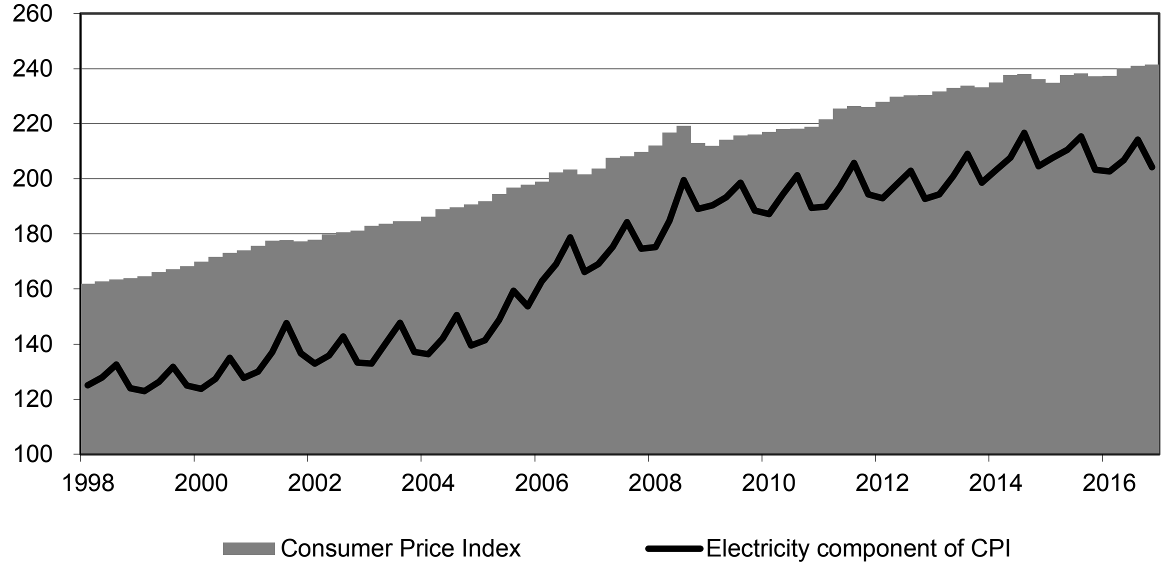
Government Guides Rates, Construction

Regulators once encouraged utilities to construct ample generating plants to satisfy vigorously growing electric demand. During the late 1970s, however, electric demand slowed significantly as that decade's energy crises sparked large increases in electric rates. Meanwhile, the cost of nuclear plant construction skyrocketed because of the Three Mile Island nuclear accident in Pennsylvania in 1979.

In response to those developments, regulators often disallowed or delayed cost recovery for plant investments deemed imprudent or unnecessary. In the wake of those disallowances, utilities became hesitant to undertake major capacity-related construction projects, and many chose to rely on power purchased from other generators.

When generating capacity appears unable to meet the levels of power required during periods of great demand (such as during "above-normal" heat waves), resulting in significant power shortages, utilities or independent power generators have found themselves compelled to increase their generating capacity. This was the case with the California power crisis in 2000, which resulted from the state's insufficient power supplies; it led to an accelerated approval process for new plants. A nationwide expansion of power plants ensued, resulting in an excess of power-generating capacity. Meanwhile, demand was greatly reduced due to a longer-than-expected weakness in the economy.

COST OF ELECTRICITY vs CONSUMER PRICES
(index, 1982–1984 = 100; quarterly data)



Source: US Bureau of Labor Statistics.

Rate Structures That Motivate

It has been argued that traditional utilities regulation—in which rates are based on the cost of service, plus a risk component—does not give utilities an incentive to become efficient. Hence, many states are examining the need to reform the cost-based framework.

Incentive Regulation Mechanisms

An alternative to cost-of-service ratemaking exists in the form of "incentive regulation mechanisms," which, at one point, were prevalent in the telecommunications industry. Through incentive mechanisms, utility managements are given performance targets. If the utility exceeds its target, it will share part of the resulting benefits through incremental increases in its allowed return on equity (ROE). Examples of incentive-based ratemaking include performance-based pricing, revenue sharing, and price-cap regulation.

◆ **Performance-based pricing.** Utilities that have settlement agreements on new nuclear plants or nuclear plants that have suffered prolonged outages use this ratemaking mechanism. It entails removing the plant from the rate base and extracting related operating expenses from those included in the utility's cost of service. Instead of earning a rate of return based on assets specified by regulators, a utility using performance-based pricing earns a preset price per kilowatt-hour (kWh) that the plant produces, making recovery dependent on plant performance. The most notable example is Pacific Gas & Electric Co.'s Diablo Canyon nuclear plant in California; the company announced on June 21, 2016 that it plans to close the plant by 2025.

◆ **Revenue sharing.** This method seeks to compensate a utility for greater-than-average risk when its cost of capital is estimated. The utility is assured that benefits resulting from gains in productivity or efficiency are shared between customers (in the form of lower rates) and shareholders (as higher earnings). Some electric utilities in New York and California currently use revenue sharing.

◆ **Price-cap regulation.** Common in the telecommunications industry, this regulation sets a ceiling for consumer prices. The price cap is intended to cover a reasonable cost of service, while letting utilities choose the most efficient way to provide that service. The choice of services that a utility may offer a specific customer currently is subject to state regulatory review.

The Laws That Shape the Industry

Several pieces of federal legislation have shaped the US electric utilities industry over time. Below are brief descriptions of some of these laws and their immediate and ongoing impact.

◆ **The Federal Power Act.** Also enacted in 1935, this law created the Federal Power Commission (later renamed the Federal Energy Regulatory Commission, or FERC) to regulate the interstate transmission and sale of electric power, and to license hydroelectric plants.

◆ **The Public Utility Regulatory Policies Act (PURPA) of 1978.** By the 1970s, the regulatory framework that had been in place for some 40 years was in need of change. That decade's energy crises generated widespread support for reducing US dependence on nonrenewable sources of energy in general and on foreign oil in particular.

To promote national self-sufficiency in energy consumption, Congress enacted PURPA in 1978. As part of this legislation, the FERC was ordered to develop rules to encourage alternative energy sources and cogeneration by creating qualifying facilities (QFs), a special class of independent power producers (IPPs).

The small generators that QFs owned were exempt from Public Utility Holding Company Act of 1935 (PUHCA) restrictions. Utilities were required to purchase the firms' electricity at prices mandated by state regulators, typically set at the utility's "avoided cost," or the cost that a company in the electric utilities industry would incur to produce or otherwise procure electric power. Although PURPA did not exempt the larger IPPs from PUHCA, it nonetheless had a significant impact on the growth of non-utility generation.

◆ **The National Energy Policy Act (NEPA) of 1992.** By reforming PUHCA, this law greatly increased competition within the electric utilities industry at the level of both production and sale of wholesale power; the latter having become the industry's most lucrative business when demand is high. Under NEPA, the FERC was empowered to direct an electric utility to provide wholesale wheeling, or transmission service, at cost from any electricity-generating entity to another utility, regardless of whether the transmitting entity is another utility or an IPP.

Under NEPA's terms, transmitting utilities must receive compensation for providing wholesale wheeling services. The FERC sets rates for transmission service at a level that lets a company fully recover the "legitimate and verifiable" costs of providing the service.

NEPA created an additional class of IPP—the exempt wholesale generator, or EWG—that was free from regulation under PUHCA provisions. Unlike IPPs of the past, however, EWG projects could have investor-owned utilities as majority interests. Affiliated EWGs can produce and sell electric power at the wholesale level; state commissions regulate these transactions. NEPA also allowed EWGs to operate outside the US and to compete in foreign markets at the retail level.

Enactment of Electricity Legislation

In August 2005, President George W. Bush signed into law a comprehensive energy bill called the Energy Policy Act of 2005 (EPAct 2005). The electricity portion of the new legislation—called the Electric Reliability Act of 2005—made grid-reliability standards mandatory, repealed the PUHCA, and authorized federal permits for transmission lines. The main electricity provisions contained in the new law are outlined below.

Public Utility Holding Company Act Repealed

The legislation repealed the PUHCA of 1935. PUHCA was enacted to eliminate the abuses committed by the holding companies of that period, such as excessive charges for "services" provided to the operating utilities that were then passed on to the consuming public. PUHCA restricted the non-utility activities of holding companies and required that the service territories of the utility operating companies be contiguous.

The law required that holding companies maintain and make available (to both the FERC and the appropriate state commissions) any books and records deemed relevant to the costs incurred by a utility within a holding company. In addition, both the FERC and the state commissions would maintain their authority to ensure that jurisdictional rates were just and reasonable, to prevent cross-subsidization, and to determine whether a utility would be allowed to recover, via rates, costs related to another company within the holding company.

While new mergers still require approval by the FERC and state utility commissions, the legislation required the US Department of Energy (DOE) to review the extent to which the FERC's merger authority was duplicative of other federal and state merger authorities, and imposed statutory deadlines intended to accelerate the merger review process.

Establishment of Electric Reliability Organizations

To address reliability issues highlighted by the power blackout of August 2003, the new law made several amendments to the Federal Power Act of 1935. It created a new section in the law, Section 215, which calls for the establishment of a self-regulating, electric reliability organization (ERO) under the jurisdiction of the FERC. The law also authorized the FERC to establish ERO requirements, including regulations allowing the ERO to delegate authority to a regional entity for the purpose of proposing and enforcing standards that would ensure the reliability of the bulk power system.

Although the EROs and any regional entities given enforcement authority would not be considered departments or agencies of the US government, the FERC was authorized to take whatever actions it considered necessary to ensure compliance with reliability standards or related commission orders. The law does not preclude individual states from taking actions aimed at ensuring the reliability of the bulk power systems situated in those states, as long as those actions are consistent with the reliability standards.

The Regulator's Role

The FERC, a division of the DOE, exercises jurisdiction over wholesale utility sales and certain transactions between affiliated companies. It also oversees utilities' issuance of certain stock and debt securities, the assumption of obligations and liabilities, and mergers.

State public utility commissions regulate electricity sales to end-use customers, such as homeowners and businesses. Regulation seeks to ensure that consumers receive reliable service at a fair price. It gives each utility the opportunity—not a guarantee—to earn an adequate return so that it can attract new capital to develop and expand plants to meet customer demand. Regulation also aims to ensure public safety and to prevent unreasonable prices, excessive earnings, and discrimination against customers.

Regulated Monopolies Move Toward Competition

In the past, individual companies operated as natural monopolies. In theory, a natural monopoly should provide economies of scale, efficient service, and lower prices. However, if the owners of such a monopoly control an essential resource, they can profit excessively. The federal government regards the supply of electricity as a necessity; thus, federal and state governments have long supervised the industry through close regulation.

"Regulatory compacts" have enabled states to grant investor-owned utilities exclusive service territories in exchange for the utility's "obligation to serve" all consumers in that territory on demand. This obligation requires utilities to build, operate, and maintain generating plants, and transmission and distribution systems that would service all present and future customers. Such franchise agreements allow the highly capital-intensive utility companies to raise the necessary financing, recover their fixed costs over time from a stable customer base, and enjoy increased efficiency through economies of scale.

The pricing process is the most significant difference between regulated utilities and competitive enterprises. Whereas market forces and competition determine how much an unregulated company can charge for its products or services, a state regulatory commission establishes a utility's rates in a rate-case proceeding. Once set, rates generally do not change without another rate case.

While the wholesale power market has been opened up to competition in many states, the scandals related to Enron and other power marketing operations have helped many state regulatory commissions decide not to pursue deregulation of generation assets. CFRA also expects interstate electric transmission to remain regulated by FERC in the US, and electric distribution to remain completely regulated by the localities and states in which they provide service due to the local monopolies granted to them by the regulators.

FERC Rulings Pulled the Plug on Monopolies

In March 1995, the FERC released a watershed Notice of Proposed Rulemaking (NOPR), alerting the industry that it had targeted the wholesale power market for deregulation and was about to issue new rulings on open access transmission. (A NOPR is a notice to the industry that the FERC is revising its regulations and will release an official ruling later.)

On April 24, 1996, the FERC issued the expected rulings, which consisted of two separate orders. The first, Order 888, addressed both open access and stranded-cost issues. The second, Order 889, required electric utilities to establish electronic systems to share information about available transmission capacity.

The FERC rulings initially targeted the wholesale power market, where electric power is provided to utilities, which then distribute it to the retail market. The agency believed that, in the long term, the rulings would reduce the need to regulate bulk power sales. It expected the opening of the transmission system to increase competition and lower prices by eliminating the power generation monopoly at the electric plant level.

◆ **Order 888.** This order addressed two principal issues: transmission service and "stranded costs."

Transmission service. Order 888 required public utilities that own, control, or operate transmission lines to provide transmission service for wholesale transactions on an open, nondiscriminatory basis. The order set guidelines for efficient operation of the transmission system, and for terms and conditions of service. It required utilities to file open access transmission tariffs stating the minimum conditions under which they can provide both network and point-to-point service. Order 888 did not mandate either corporate unbundling or divestiture of assets, but it did establish standards of conduct to ensure this functional unbundling.

In issuing this order, the FERC supported the concept of independent system operators (ISOs), although it did not require utility companies to join them. Each ISO controls the operation of interconnected transmission facilities within a certain region. It also is responsible for ensuring nondiscriminatory, open access transmission, as well as the planning and security of the utilities' combined bulk transmission systems.

Stranded costs. This term refers to the money a utility could lose if it were unable to recover its investment in generating plants, and/or other deferred costs, such as those incurred when a wholesale customer switches providers or types of service. In Order 888, the FERC endorsed the principle of full recovery of prudently incurred wholesale stranded costs. The FERC thus reaffirmed its view that utilities should be able to recover these costs from departing customers by negotiating remedies before the end of the contract.

◆ **Order 889.** Also known as the Open Access Same-Time Information System (OASIS) rule, Order 889 required electric utilities to do two things. First, each utility must make available electronically, to other utilities and electricity providers, certain information about its transmission systems—the information that it would use for its own wholesale power transactions. Second, each utility's wholesale power marketing must be administered and accounted for separately from its transmission operation functions, enabling customers to compare prices for these services—a change from past practices, when the services were bundled.

◆ **Order 2000.** Although orders 888 and 889 encouraged the formation of ISOs, they still left management of the transmission grid to the vertically integrated electric utilities. The FERC eventually concluded that this structure was not efficient or reliable enough to support the development of genuinely competitive electricity markets.

To promote efficiency in wholesale electricity markets and to ensure that consumers pay the lowest possible price for reliable service, the FERC issued Order 2000 in December 1999. Its objective was to encourage all public and nonpublic electric utilities to place their transmission facilities under the independent control of a regional transmission organization (RTO). The function of an RTO is to control the transmission grid in a given regional territory, thus assuring nondiscriminatory access while increasing efficiency and reliability. Although similar in concept to the ISO, the RTO would have more authority to eliminate discrimination.

Order 2000 established the minimum characteristics and functions for an RTO: independence from market participants, a sufficient geographical scope and regional configuration, a clear operational responsibility and authority, and the ability to assure short-term reliability. The order encouraged a collaborative process whereby all utilities that own, operate, or control interstate transmission facilities could consider and develop RTOs in consultation with state officials.

◆ **Order 890.** The EPAct 2005 authorized the FERC to prescribe rules to provide for the dissemination of information about the availability and price of wholesale electric power and transmission service. The FERC strongly believed that, more than 10 years after Order 888, the open access transmission tariffs (OATTs) contained flaws that undermined its core objective of preventing undue discrimination by transmission owners. To change this, the FERC issued Order 890 on February 16, 2007—authorizing several reforms.

First, it eliminated the wide discretion that transmission providers have in calculating available transfer capacity. Second, it required an open, transparent, and coordinated transmission-planning process. Third, it increased the efficient utilization of transmission by eliminating artificial barriers (such as denying a request for long-term, point-to-point service if the request cannot be granted in an hour). Fourth, it facilitated the use of clean energy resources, such as wind power, through reforming generator imbalance charges (since these resources have limited ability to control their output). Last, Order 890 increased the clarity of OATT requirements and strengthened compliance and enforcement efforts by adopting penalties for clear violations of an OATT.

Industry Accounting Quirks

The industry's regulated nature has given rise to unique accounting practices. In particular, several significant "noncash" items can dramatically alter a utility's earnings. Historically, the most notable noncash component in accounting has been the allowance for funds used during construction (AFUDC). If state regulators do not include a utility's construction work in progress (CWIP) in the calculation of its rate base (upon which the utility is allowed to earn an actual return), the utility records an AFUDC on its income statement. This is an income credit representing construction financing costs. Once the facility is placed into operation, a return will be earned on the portion of those costs included in the rate base. The costs not included in the rate base will be recovered over the life of the facility through depreciation charges.

AFUDC amounts are added to a plant's costs. Like other construction expenditures, they are depreciated over time. During periods of heavy construction, AFUDC could represent a substantial portion of utility earnings, but are of much less significance during periods of limited construction spending.

Another source of noncash earnings is multi-year phase-ins of rate hikes given to utilities to cover costs for new generating plants. This practice generates noncash earnings in that the reported "earnings" do not include the related expense that has been recorded as an asset on the balance sheet under deferred charges. By phasing in these large rate increases, regulators lessen the "rate shock" to customers. To avoid the negative earnings impact from enormously expensive projects, utilities can defer the recording of these costs while new rates are phased in. Such deferred amounts then are amortized and recovered over time.

Many state commissions require or allow utilities to create "regulatory assets" by deferring the recording of some costs—such as those related to damages from severe storms, clean air expenditures, and demand-side management energy-efficiency programs—until the next general rate increase. For some utilities, the next expected general rate increase might be years away, so reported earnings would be affected only in the long term. However, the deferred costs hurt the quality of near-term earnings, because the earnings do not fully reflect the costs of that period. Suppose, for example, that a company incurs a $100 million expense for repairing storm damage. The company's current reported earnings would not be affected because the expense has been deferred, but this compromises the quality of those earnings. Regulatory assets are only appropriate if it is probable that they will be amortized and recovered once the next rate increase becomes effective.

KEY INDUSTRY RATIOS AND STATISTICS

◆ **Allowed ROE, allowed ROA, and equity ratio.** These statistics are relatively common inputs for setting regulated utility electricity rates. The higher the allowed return on assets (ROA), and the lower the allowed equity-to–total-capitalization ratio, then the higher the allowed return on equity (ROE) will be.

◆ **Cooling- and heating-degree-days.** Cooling- and heating-degree-days are measures of the average temperature for a given period. Mean temperatures below a reference temperature, usually 65 degrees Fahrenheit, result in heating-degree-days; those above the reference temperature result in cooling-degree-days. Reported by both the Edison Electric Institute (EEI) and the Climate Prediction Center of the National Weather Service, these statistics have an important bearing on utility earnings, in that electricity delivered typically increases when it is hotter than normal in the summer or, to a much lesser extent, when it is colder than normal in the winter.

◆ **Electricity rates.** These rates, generally set by regulatory authorities, are the price charged by electric utilities for the electricity that they deliver. Rates at vertically integrated utilities incorporate both the production and distribution of electricity.

◆ **Generating capacity total and capacity by fuel source.** Most electric utilities are still vertically integrated. Those that are integrated have power plants that generate electricity to be sold to their own customers or into wholesale electric markets. Hydro, nuclear, and coal plants, as well as some combined-cycle natural gas plants tend to run 24/7, while smaller peaking plants tend to run only when electric demand is highest and intermittent power sources, such as solar and wind, tend to run whenever they are available.

◆ **Interest rates.** The regulated and capital-intensive nature of the electric utilities industry makes the financial performance of these companies very sensitive to the level of interest rates and available returns. Utility rates are based on operating costs, capital investments, and the cost of capital. Changes in overall market rates affect utility rates via the cost of debt and the allowed ROE. When market rates drop substantially, utilities rates will likely be lowered as financing cost savings are passed on to customers.

In addition, income-oriented investors are sensitive to interest rates when evaluating a utility company's shares. If interest rates are rising, these investors may be able to receive comparable returns elsewhere and, consequently, would be less likely to purchase a utility stock that did not provide a comparable yield.

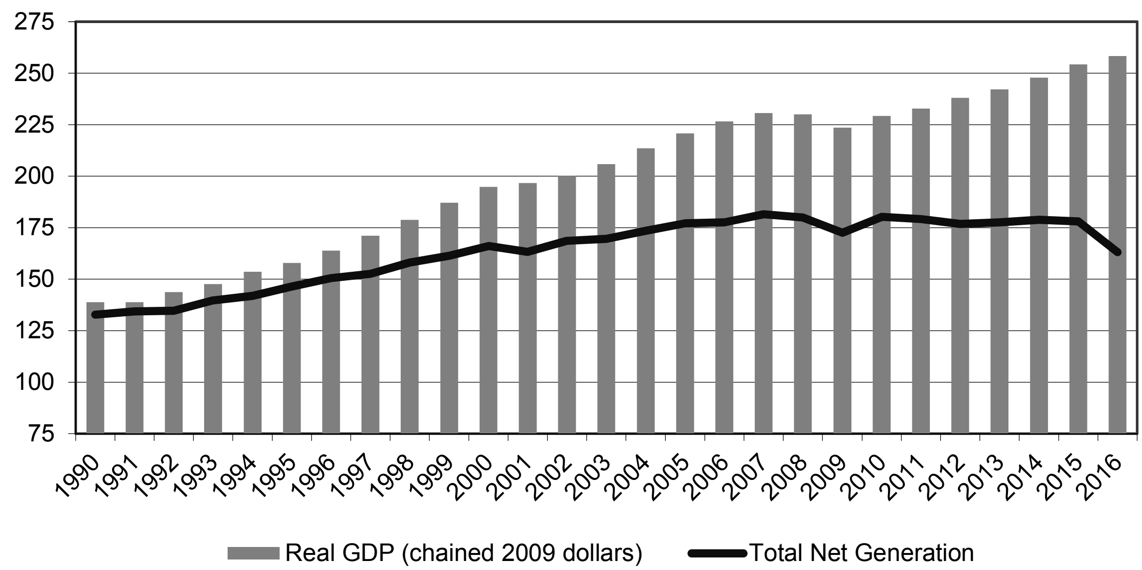
◆ **Key demographic and housing statistics.** Demographic trends can influence the customer base of a company in the electric utilities industry. New household formations and the rate of new housing construction are the key sources of residential customer growth. The US Census Bureau reports household formations, while the US Department of Commerce (DOC) reports housing starts monthly.

◆ **Total electricity delivered and electricity delivered by customer class.** Electric deliveries are ultimately the main volume driver of utility revenues. Rates charged (prices) for electricity delivered also help to determine electric utilities revenues. Each customer class typically has a certain rate for electricity, with residential users typically paying the most and large industrial users paying the least.

◆ **US gross domestic product.** Reported quarterly by DOC, gross domestic product (GDP) is a broad measure of aggregate economic activity. It is the market value of goods and services produced by labor and capital in the US. Growth in the economy is measured by changes in inflation-adjusted (or real) GDP.

Changes in demand for electricity closely mirror the rate of economic growth. However, weather patterns can cause swings in electric consumption. In addition, demand growth for an individual utility company depends heavily on economic trends within its geographic region.

REAL GDP AND TOTAL KILOWATT-HOUR SALES
(1980=100)



Sources: US Bureau of Economic Analysis; US Energy Information Administration.

HOW TO ANALYZE A COMPANY IN THIS INDUSTRY

The job of analyzing a company in the electric utilities industry is becoming increasingly complex as the industry moves toward a deregulated, competitive marketplace. A fair assessment now requires much more than a look at the dividend yield (the annual dividend divided by the stock price). When evaluating a company in this industry, it is as important to assess the utility's underlying business position as it is to determine its current financial health.

Qualitative Factors

Important factors that affect a company's business position in the electric utilities industry include the following:

Location

The ideal environment for a utility is one in which a robust economy attracts new businesses that, in turn, contribute to above-average population growth. Is economic activity in the utility's service region healthy and growing? What is the area's outlook for population growth and new housing starts? What are the forecasts for future regional demand?

Customer Mix

A utility's customer base has an important bearing on its profitability level. A utility with a large industrial and commercial load should be viewed with caution, because these customer classes expose the utility to competition. A large residential customer base, in contrast, provides a more stable and predictable earnings stream. (The introduction of residential competition is not likely to affect this situation any time soon; most residential customers are expected to remain with their current utility.)

If any single wholesale or retail customer accounts for a significant portion of a utility's sales, the analysis must focus on the stability of that customer and on the utility's competitive position—its prospects for retaining that company's business.

Competitive Position

A company's rates and its ability to lower production costs generally determine its position relative to competitors. A high-volume customer could choose to relocate to a different service area with lower rates or to buy power from an independent producer. A large industrial customer could turn to self-generation or nontraditional energy sources.

How do the utility's production costs and rates compare with those of other utilities in the same region and with the national average? Examine the utility's plans for capital additions. How much is it expecting to spend? How will its plans be funded? As competition increases, utilities must become even more careful about capital additions, questioning whether the future customer base will support the additional costs.

Fuel Mix and Supply

A utility company's ability to alter its generating sources (such as coal, nuclear power, hydroelectric power, gas, and oil) defends it against supply disruptions or price spikes in a particular commodity. It also lets the company take advantage of changes in fuel costs. Conversely, a lack of flexibility in fuel supply restricts a company's options if the environment changes.

Plant Operations
Areas for analysts to consider include the various costs to run the plants, the reliability of the operations, and the quality of the service. Have there been any unscheduled outages? What are the current estimates of remaining plant life and decommissioning costs? Will it be profitable to run the plant(s) in a competitive market? Does the company have idled or excess capacity? If so, what are its plans?

In addition, look at the utility's transmission access. Is it adequate for current demand? Is the company locked into any long-term purchase power contracts with high-price non-utility generators? If competition drives down the industry's production costs and market prices, the utility would suffer from contractual obligations to purchase power at above-market rates.

Business Strategy
The electric utilities industry offers little in the way of domestic growth prospects, given its maturity. For that reason, many utilities had attempted to achieve growth through investments in wholesale energy marketing and trading operations, and/or other energy-related businesses, as well as in utilities in foreign countries. Such ventures, however, added a significant risk component to their operations, and often resulted in serious economic losses and even bankrupt businesses. One must determine whether the utility's business strategy and management are conservative or aggressive, and whether they are appropriate in light of the company's strengths and culture, and the opportunities available to it.

The Regulatory Environment
Electric utilities' activities remain subject to extensive state and federal regulation, despite the eventual arrival of retail competition. Regulated areas include consumer rates, allowed rates of return, the safety and adequacy of service, the purchase and sale of assets, accounting systems, and the issuance of securities.

Therefore, it is important to study the trends at the regulatory commissions that have jurisdiction over a utility. Compare the recent average return on equity (ROE) that the commission authorized for the utility with the amount the utility requested. Was the ruling favorable? If not, why? Is there a possibility of a rate decrease? When will the next rate increase (or decrease) be filed? What other major issues will be addressed?

What are the local commission's views on retail competition and regulatory reform? On stranded-cost recovery, demand-side management programs, and clean air compliance? All of these factors can affect a utility's ultimate revenues.

Evaluating the Income Statement

At this point, one should have a good idea of how well the utility being analyzed is positioned to compete in the current changing environment and its own particular markets. Now it is time to look at the financial statements, beginning with the income statement.

Revenue Growth
Revenue growth for utilities is somewhat predictable because of regulatory constraints on price increases. Nevertheless, it is still important to study past sales trends and expectations for the future. Did growth come from a rate hike or from increased weather-related demand? Is the economy improving and is the population growing in the utility's service area?

Operating Expenses

Fuel is the largest and most variable item on a utility's list of operating expenses, and it is often the least controllable. Note whether the company has been able to pass along higher fuel costs to customers. Pay close attention to nonfuel expenses, and particularly to how they compare with revenues. An improving trend in operating and maintenance costs usually indicates that a company is focusing on streamlining its operations and controlling costs.

Noncash Items

Unique to the analysis of utility companies are certain noncash items that can make a big difference in the quality of reported earnings. These items include the treatment of deferred income taxes, deferred expenses, phase-ins, depreciation and amortization, and the allowance for funds used during construction (AFUDC). If any of these items constitutes a significant portion of reported earnings, the results may be overstated or unsustainable.

Study the trends in depreciation and amortization charges. Given the current competitive environment and the possibility of stranded investments, many utilities are accelerating the write-down of at-risk assets. A higher depreciation rate depresses a utility's current net earnings, but analysts view the tactic as a positive step, because accelerated depreciation helps a utility recover the costs of its investments more quickly.

STATEMENT OF INCOME—INVESTOR-OWNED UTILITIES

(in millions of dollars, except as noted)

ITEM	---- 3RD QTR ----		% CHG.
	2015r	2016	
Total electric operating revenues*	95,095	98,013	3.1
Electric operating expenses			
Energy expenses	31,434	29,822	(5.1)
Operations & maintenance	22,651	23,649	4.4
Depreciation & amortization	10,766	12,019	11.6
Taxes (other than income)	4,557	4,800	5.3
Other operation & maintenance	2,870	3,416	19.0
Total operating expenses	72,277	73,706	2.0
Total utility operating income	22,818	24,307	6.5
Total other recurring revenue	786	1,510	92.1
Nonrecurring revenue	68	1,053	1,455.8
Net interest expense	5,322	5,921	11.2
Other expenses	111	87	(21.9)
Asset writedowns	2,774	2,590	(6.6)
Nonrecurring expenses	3,138	3,150	0.4
Net income before taxes	15,100	17,713	17.3
Net income before extraordinary items	10,522	12,435	18.2
Total extraordinary items	(212)	120	NM
NET INCOME	10,309	12,555	21.8

Note: 2015 figures shown are revised. *Revenues are adjusted for intra-industry sales for the resale of electricity. NM-Not meaningful.
Sources: SNL Financial; Edison Electric Institute Finance Department.

Non-Operating Expenses

Because the utilities industry is extremely capital-intensive, interest payments are its most significant non-operating expense. Since the mid-1980s, however, interest costs have trended downward, largely because industry overcapacity has resulted in reduced capital expenditures and construction. If interest expenses are increasing, find out why.

Balance Sheet and Cash Flow Measures

The capitalization ratio, debt ratings, cash flow, and ROE are all measures of a company's financial strength and performance.

BALANCE SHEET DATA—INVESTOR-OWNED UTILITIES
(in millions of dollars)

ITEM	---- 3RD QTR ---- 2015r	2016	% CHG.
ASSETS			
Utility plant			
Gross property & equipment	1,281,990	1,365,867	6.5
Accumulated depreciation	389,419	403,470	3.6
Net property in service	892,572	962,397	7.8
Construction work in progress	53,513	56,042	4.7
Net nuclear fuel	8,892	8,849	(0.5)
Other property	7,333	17,621	140.3
Net property & equipment	962,310	1,044,909	8.6
Current assets	125,231	120,090	(4.1)
Investments	79,270	86,290	8.9
Other assets	222,816	244,539	9.7
Total assets	1,389,626	1,495,827	7.6
CAPITALIZATION & LIABILITIES			
Common equity	394,618	410,102	3.9
Nonredeemable preferred equity	54	15	(72.0)
Noncontrolling interests	8,049	9,602	19.3
Total shareholders' equity	402,722	419,720	4.2
Short-term debt	25,801	31,258	21.2
Current portion of long-term debt	27,362	27,790	1.6
Short-term and current long-term debt	53,163	59,048	11.1
Accounts payable and accrued expenses	55,424	59,881	8.0
Other current liabilities	35,095	34,576	(1.5)
Current liabilities	143,683	153,504	6.8
Deferred taxes	145,404	155,935	7.2
Noncurrent portion of long-term debt	434,166	486,076	12.0
Other liabilities	266,427	284,818	6.9
Total liabilities	989,679	1,080,333	9.2
Total mezzanine level	865	662	(23.5)
Total Liabilities and Equity	1,393,265	1,500,715	7.7

Note: 2015 figures shown are revised.
Sources: SNL Financial; Edison Electric Institute Finance Department.

Capitalization Ratios

When analyzing a utility's balance sheet, pay close attention to the capitalization ratio, which measures long-term debt as a percentage of capital. Historically, utilities have been highly leveraged. The main factors influencing the level of debt are the level of capital expenditures, particularly construction expenditures, and the cost of debt compared with the value of the company's common stock. (A company will not issue new shares if its stock price is relatively low.) Companies with strong balance sheets will have more flexibility to further reduce their debt, invest in their non-regulated businesses, and/or increase their dividends.

Debt Ratings

A debt rating measures a company's financial position and its ability to repay debt. The Standard & Poor's ratings for a utility's debt securities are a good indication of a company's financial security. Analysts should look for any trends in these ratings over time. Have they changed for the better or the worse?

Although a high debt rating is usually desirable, it is not always the best news for shareholders. For example, a company that focuses on using earnings (cash) to pay off debt may do so at the expense of common stock dividend payments. As a rule, however, low debt ratings are not desirable. Companies with low ratings often find it hard to raise capital; they also incur high interest payments to finance capital improvements. If the stock price is low enough, however, the utility's shares may be attractive to investors.

Cash Flow

A review of cash flow trends helps to reveal the health of an electric utility. For an equity analyst, it is more important to look at free cash flow—what is left after interest and dividend payments have been made. A company struggling with cash flow problems may have to consider cutting dividends or freezing dividends at current levels to preserve funds.

CASH FLOW STATEMENT—INVESTOR-OWNED UTILITIES
(in millions of dollars)

ITEM	---- 3RD QTR ---- 2015r	2016	% CHG.
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	10,308	12,555	21.8
Depreciation and amortization	11,586	13,240	14.3
Deferred taxes and investment credits	3,103	4,228	36.3
Operating changes in AFUDC	(327)	(331)	NM
Change in working capital	2,357	584	(75.2)
Other operating changes in cash	3,600	1,294	(64.1)
Net cash provided by operating activities	30,627	31,569	3.1
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(25,190)	(26,550)	NM
Net non-operating asset sales and purchases	(2,480)	(14,200)	NM
Change in nuclear decommissioning trust	148	(65)	NM
Investing changes in AFUDC	21	30	45.0
Other investing changes in cash	(531)	7,035	NM
Net cash used in (provided by) investing activities	(28,032)	(33,751)	NM
CASH FLOWS FROM FINANCING ACTIVITIES			
Net change in short-term debt	(1,897)	(889)	NM
Net change in long-term debt	3,744	11,820	215.7
Proceeds from issuance of preferred equity	337	0	(100.0)
Preferred share repurchases	(419)	(315)	NM
Net change in preferred issues	(82)	(315)	NM
Cash flow: proceeds from issuance of common equity	3,203	3,698	15.5
Cash flow: common share repurchases	(117)	(15)	(87.1)
Net change in common issues	3,085	3,683	19.4
Dividends paid to shareholders	(5,633)	(6,036)	NM
Other financing changes in cash	(48)	162	NM
Cash flows from financing activities	(832)	8,425	NM
Other changes in cash	(10)	(8)	NM
Net increase (decrease) in cash and cash equivalents	1,753	6,235	255.6
Cash and cash equivalents at beginning of period	18,409	12,945	(29.7)
Cash and cash equivalents at end of period	20,163	19,180	(4.9)

Note: 2015 figures shown are revised.
NM-Not meaningful. AFUDC-Allowance for funds used during construction.
Sources: SNL Financial; Edison Electric Institute Finance Department.

Return on Equity

If a utility's ROE is too low, the analyst must determine if it was caused by mild weather or the absence of a needed rate hike—or if the utility is poorly operated. Conversely, an ROE that is too high could cause regulators to seek a rate cut. For firms in the S&P 1500 electric utilities index, the average ROE generally ranges between 10% and 13%, although the average is slightly below that range for 2015.

Valuation Measures

Stock price figures as a variable in the measures described below, so they indicate the market's valuation of a company's current and potential future performance.

Market-To-Book Ratio

The market-to-book (or price-to-book) ratio is used to measure shareholder confidence in a company's prospects. It is calculated by dividing the company's current market price per share by the company's book value per share. A low market-to-book ratio could mean that a company has assets, such as nuclear generation facilities, that are no longer economically viable. For firms in the S&P electric utilities index, shares normally trade between one and two times the company's book value per share.

P/E Ratio and Dividend Yield

To evaluate the current market price of the utility's shares, look at the price-to-earnings (P/E) ratio and the dividend yield. Is the P/E ratio greater or less than the expected sustainable growth rate of the company's earnings? How does the P/E compare with the industry average? Investors tend to pay a higher P/E and to accept a lower dividend yield from the shares of a company with earnings that are expected to rise rapidly.

For firms in the S&P electric utilities index, shares normally trade between 12 and 18 times the company's projected earnings per share (EPS). These shares tend to trade at a discount to the market multiple because of the slow-growth nature of utilities' regulated operations. Dividend yields normally range from 3% to 6%. Because of these higher-than-average dividend yields, dividend income is an important component of investors' total return on electric utilities stocks. The importance of the dividend was significantly increased in May 2003, when President Bush signed legislation that cut the tax rate on dividend income from the earned income rate to a 15% rate.

Despite the importance of the dividend (especially for income-oriented investors), electric utilities stocks are much less interest-rate sensitive than they were in the past. In fact, the value of electric utilities stocks declined in both 2001 and 2002, despite a significant decline in interest rates. This primarily reflects the perception of investors that other industries may benefit more from a drop in rates.

In 2007, although there was a coincidence between the decline in interest rates and the rise in utility stocks, CFRA thinks the latter was more affected by the weakness of the overall market. Utility stocks appear to benefit the most—as they did in 2004, 2005, and 2007—when the broader market is in a state of decline or uncertainty and investors are looking for a "safe haven" for their investments.

GLOSSARY

Allowance for funds used during construction (AFUDC)—On the income statement, this noncash item represents the estimated composite interest costs of debt and the allowed return on equity (ROE) used to finance a utility's construction. AFUDC is capitalized in the property accounts.

Avoided Cost—The cost that an electric utility would normally incur to produce or procure electric power, but which it does not incur because it has purchased that power from a qualifying facility.

Baseload—The minimum constant level of electric power delivered or required in a given time period.

Baseload unit—An electricity-generating plant, or a generating unit within a plant, that normally is operated continuously to meet the system's minimum constant level of electric demand.

Construction work in progress (CWIP)—A balance sheet account that shows all costs associated with the construction of new utility facilities until these facilities are placed in service. These costs may or may not be included in the rate base.

Cost of capital—The sum of the weighted cost of capital for each funding source: long-term debt, preferred stock equity, and common stock equity.

Cost of service—In public utility regulation, the total costs incurred to supply utility service; it is the chief determinant of the rate of return allowed a utility.

Cycling unit—An electricity-generating plant, or generating unit within a plant, that can vary its level of operation in response to changes in electric demand. Cycling units are intermediate load units that are usually used to meet demand that exceeds the baseload (the minimum constant level of demand).

Decommissioning costs—Expenses incurred in the removal and disposal of components of a nuclear power plant that has permanently stopped producing electricity.

Degree-day—A unit of measure expressing the extent to which temperatures vary from a specific reference temperature (usually 65 degrees Fahrenheit) during a given time period; each degree above or below the benchmark equals one degree-day. Thus, a given period (month, quarter, or year) during which the mean temperature is 55 degrees would be considered as 10 heating-degree-days. This usually would be compared with the prior period and the historical average.

Demand-side management—The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage.

Deregulation—The process of decreasing or eliminating government regulatory control over industries in the expectation that competitive forces will drive the market.

Disallowance—A regulatory body's determination that certain costs a utility incurred are not recoverable from the utility's customers through rates. Such costs could include those that regulators find to be unwise, excessive, unaccounted for, or caused by lack of proper foresight.

Electric distribution system—The portion of an electric system dedicated to delivering electric energy to end-users. It links the transmission system and most customers.

Electric transmission—The transportation of bulk quantities of electric energy, via electric conductors, from generation sources to an electric distribution system, a load center, or an interface with a neighboring control area.

Firm power—Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

General rate case—The major regulatory proceeding during which regulators examine in depth a utility's costs and operations, as part of the overall process of determining utility rates.

Generator—A machine that converts mechanical energy into electrical energy; also, a company that uses such machines to generate electrical energy.

Gigawatt—A unit of power or capacity equal to one billion watts.

Independent power producers (IPPs)—Non-utility power-producing entities that are not qualifying facilities (QFs); they typically sell the power they generate to electric utilities at prevailing wholesale prices. The utilities then resell this power to their customers.

Independent system operators (ISOs)—An entity formed to control and operate a regional transmission system; the individual parts of the system have different owners. Commissions in each state determine the rules for ISOs.

Interruptible load—Program activities that can interrupt consumer load during seasonal peak times, in accordance with contractual arrangements.

Kilowatt—A unit of power or capacity equal to one thousand watts.

Load—The amount of power carried by a utility system or subsystem, or the amount of power consumed by an electric device at a specified time; also referred to as demand.

Load factor—The ratio of the actual electric energy consumed during a given time period to the consumption that would have occurred at the peak demand level.

Megawatt—A unit of power or capacity equal to one million watts.

Multi-utilities—Utility companies that are comprised of both electric utilities and gas utilities

Natural monopoly—Businesses that are monopolies because of underlying industry attributes. Natural monopolies typically occur in industries in which a large capital investment is required to produce a single unit of output, making it difficult for new businesses to enter the market.

Peak demand—The maximum amount of electricity required during periods of highest usage.

Peak load—The maximum amount of energy carried by a utility system during a specific period. Peak load determines the required system capacity.

Peaking unit—An electricity-generating plant (or a generating unit within a plant) designed to produce electric energy on short notice and for relatively brief periods. Peaking units are used when all other units and energy sources are operating at their maximum capability.

Power pool—An association of two or more interconnected electric systems that have agreed to coordinate operations, and to plan for improved reliability and efficiencies.

Price-cap regulation—A system of limiting rates based directly on a measure of prices (such as the consumer price index) without regard to a utility's costs.

Rate base—The value of property upon which a utility is allowed to earn a specified rate of return as established by a regulatory authority.

Rate of return (ROR)—The return earned by or allowed a utility enterprise, calculated as a percentage of the utility's rate base.

Rate structure—The combined rate components and designs a utility uses to bill its various classes of customers.

Reserve margin—The difference between an electric utility's system capability and anticipated peak load during a specified period, measured either in megawatts or as a percentage of peak load.

Revenue requirement—The total amount of money a utility must collect from customers to pay all operating and capital costs, and to receive a fair return on investment.

Scheduled outage—The shutdown of a generating unit, transmission line, or other facility for inspection or maintenance, in accordance with an advance schedule.

Stranded costs—The Federal Energy Regulatory Commission (FERC) defines stranded costs as any legitimate, prudent, and verifiable cost incurred at the wholesale level that is no longer economically viable in a competitive environment. In practice, the term generally refers to high-cost purchased power obligations to certain non-utility generators.

Tariff—Public schedules detailing utility rates, rules, service territories, and terms of service, filed for official approval with a regulatory agency.

Transformer—A device that changes the voltage of alternating current electricity.

Turbine—A machine for generating rotary mechanical power from the energy of a stream of a fluid, such as water. The rotational energy is then used to operate an electric generator or other device.

Watt—The basic unit for measuring electric power.

Wholesale sales—Energy supplied by a utility or independent power producer to other electric utilities, cooperatives, municipals, and federal and state electric agencies for resale to the ultimate customers.

Wholesale wheeling—The provision of transmission service for any electricity-generating entity that sends power to another utility.

INDUSTRY REFERENCES

PERIODICALS

Megawatt Daily
http://www.platts.com/products/megawatt-daily
Covers industry news.

Public Utilities Fortnightly
http://www.fortnightly.com
Covers the electric and gas utilities industries.

TRADE ASSOCIATIONS

Edison Electric Institute (EEI)
http://www.eei.org
Supplies industry statistics and information on electric utilities industry issues.

National Association of Regulatory Utility Commissioners (NARUC)
http://www.naruc.org
Represents individual states' viewpoints on regulation.

North American Electric Reliability Corp. (NERC)
http://www.nerc.com
Not-for-profit organization formed in 1968 by the electric utilities industry to promote the reliability and adequacy of North America's bulk power supply.

INDUSTRY CONSULTANTS

S&P Global Platts
http://www.platts.com
Consulting and publishing firm that collects strategic energy information. S&P Global Platts is a unit of S&P Global Inc.

SNL Financial LC–S&P Global Market Intelligence
http://www.snl.com
Research firm providing regulatory, financial, market, and M&A data on several industries, including energy.

GOVERNMENT AND REGULATORY AGENCIES

Federal Energy Regulatory Commission (FERC)
http://www.ferc.gov
Independent five-member commission within the US Department of Energy (DOE) that regulates interstate and wholesale electric power rates (tariffs) and transactions, as well as hydroelectric licensing and interstate natural gas pipeline companies.

US Department of Energy (DOE)
http://www.energy.gov
A position in the US Cabinet comprising the Office of the Secretary of Energy and the FERC.

US Energy Information Administration (EIA)
http://www.eia.gov
Agency within the DOE; supplies publications and statistics on the electricity industry.

US Environmental Protection Agency (EPA)
http://www3.epa.gov
Independent federal agency that formulates and enforces policies and regulations aimed at the protection of human health and the environment.

US Nuclear Regulatory Commission (NRC)
http://www.nrc.gov
Independent federal agency that regulates civilian uses of nuclear materials in the US. The NRC's main functions include inspecting plant operations, reviewing and issuing construction and operating licenses, and researching regulatory and standards development.

COMPARATIVE COMPANY ANALYSIS

Operating Revenues

Ticker	Company	Yr. End	Million $ 2015	2014	2013	2012	2011	2010	2005	CAGR (%) 10-Yr.	5-Yr.	1-Yr.	Index Basis (2005 = 100) 2015	2014	2013	2012	2011
ELECTRIC UTILITIES																	
ALE	§ ALLETE INC	DEC	1,486.4 A,F	1,136.8 F	1,018.4 F	961.2 F	928.2 F	906.3 F	737.4 D	7.3	10.4	30.8	202	154	138	130	126
LNT	[] ALLIANT ENERGY CORP	DEC	3,253.6 F	3,350.3 F	3,276.8 F	3,094.5 D,F	3,665.3 F	3,416.1 D,F	3,279.6 D,F	(0.1)	(1.0)	(2.9)	99	102	100	94	112
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	16,453.2 D,F	17,020.0 F	15,357.0 F	14,945.0 F	15,116.0 F	14,427.0 F	12,111.0 C,D	3.1	2.7	(3.3)	136	141	127	123	125
DUK	[] DUKE ENERGY CORP	DEC	23,459.0 F	23,930.0 D,F	24,549.0 F	19,624.0 A,F	14,529.0 F	14,272.0 D,F	16,746.0 C,D	3.4	10.4	(2.0)	140	143	147	117	87
EIX	[] EDISON INTERNATIONAL	DEC	11,524.0 F	13,413.0 F	12,581.0 F	11,862.0 D,F	12,760.0 F	12,409.0 F	11,852.0 C,D	(0.3)	(1.5)	(14.1)	97	113	106	100	108
EE	§ EL PASO ELECTRIC CO	DEC	849.9 F	917.5 F	890.4 F	852.9 F	914.1 F	877.3 F	803.9 C,F	0.6	(0.6)	(7.4)	106	114	111	106	114
ETR	[] ENTERGY CORP	DEC	11,513.3 F	12,494.9 F	11,390.9 F	10,302.1 F	11,229.1 F	11,487.6 F	10,106.2 D,F	1.3	0.0	(7.9)	114	124	113	102	111
ES	[] EVERSOURCE ENERGY	DEC	7,954.8 F	7,741.9 F	7,301.2 F	6,273.8 A,F	4,465.7 F	4,898.2 F	7,397.4 C,D	0.7	10.2	2.8	108	105	99	85	60
EXC	[] EXELON CORP	DEC	29,447.0 F	27,429.0 F	24,888.0 F	23,489.0 A,F	18,924.0 F	18,644.0 F	15,357.0 C,D	6.7	9.6	7.4	192	179	162	153	123
FE	[] FIRSTENERGY CORP	DEC	15,031.0 F	15,049.0 F	14,900.0 D,F	15,320.0 F	16,346.0 A,F	13,253.0 F	11,989.0 C,D	2.3	2.5	(0.1)	125	126	124	128	136
GXP	† GREAT PLAINS ENERGY INC	DEC	2,502.2	2,568.2	2,446.3	2,309.9	2,318.0	2,255.5	2,604.9 D,F	(0.4)	2.1	(2.6)	96	99	94	89	89
HE	† HAWAIIAN ELECTRIC INDS	DEC	2,603.0 F	3,239.5 F	3,238.5 F	3,375.0 F	3,242.3 F	2,665.0 F	2,215.6 D,F	1.6	(0.5)	(19.6)	117	146	146	152	146
IDA	† IDACORP INC	DEC	1,270.3 F	1,282.5 F	1,246.2 F	1,080.7 F	1,026.8 F	1,036.0 F	859.5 F	4.0	4.2	(1.0)	148	149	145	126	119
NEE	[] NEXTERA ENERGY INC	DEC	17,486.0 F	17,021.0 F	15,136.0 D,F	14,256.0 F	15,341.0 F	15,317.0 F	11,846.0 F	4.0	2.7	2.7	148	144	128	120	130
OGE	† OGE ENERGY CORP	DEC	2,196.9	2,453.1	2,867.7 F	3,671.2 F	3,915.9 F	3,716.9 F	5,948.2 D,F	(9.5)	(10.0)	(10.4)	37	41	48	62	66
PCG	[] PG&E CORP	DEC	16,833.0	17,090.0	15,598.0	15,040.0	14,956.0	13,841.0	11,703.0 D	3.7	4.0	(1.5)	144	146	133	129	128
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	3,495.4 F	3,491.6 F	3,454.6 F	3,301.8 D,F	3,241.4 D,F	3,263.6 D,F	2,988.0 D,F	1.6	1.4	0.1	117	117	116	111	108
PNM	† PNM RESOURCES INC	DEC	1,439.1	1,435.9	1,387.9	1,342.4	1,700.6	1,673.5	2,076.8 C,F	(3.6)	(3.0)	0.2	69	69	67	65	82
PPL	[] PPL CORP	DEC	7,669.0 D,F	11,564.0 D,F	11,905.0 F	12,189.0 D,F	12,737.0 A,F	8,521.0 A,C	6,219.0 C,D	2.1	(2.1)	(33.7)	123	186	191	196	205
SO	[] SOUTHERN CO	DEC	17,489.0 F	18,467.0 F	17,087.0 F	16,537.0 F	17,657.0 F	17,456.0 F	13,554.0 F	2.6	0.0	(5.3)	129	136	126	122	130
WR	† WESTAR ENERGY INC	DEC	2,459.2	2,601.7	2,370.7	2,261.5	2,171.0	2,056.2	1,583.3 D	4.5	3.6	(5.5)	155	164	150	143	137
XEL	[] XCEL ENERGY INC	DEC	11,024.5 F	11,686.1 F	10,914.9 F	10,128.2 F	10,654.8 F	10,310.9 F	9,625.5 D,F	1.4	1.3	(5.7)	115	121	113	105	111
MULTI-UTILITIES																	
AEE	[] AMEREN CORP	DEC	6,098.0	6,053.0	5,838.0 D	6,828.0	7,531.0	7,638.0	6,780.0 C,F	(1.1)	(4.4)	0.7	90	89	86	101	111
AVA	§ AVISTA CORP	DEC	1,484.8 F	1,472.6 D,F	1,618.5 F	1,547.0 F	1,619.8 A,F	1,558.7 F	1,359.6 F	0.9	(1.0)	0.8	109	108	119	114	119
BKH	† BLACK HILLS CORP	DEC	1,304.6 F	1,393.6 F	1,275.9 F	1,173.9 F	1,272.2 D,F	1,307.3 A,F	1,391.6 A,C	(0.6)	(0.0)	(6.4)	94	100	92	84	91
CNP	[] CENTERPOINT ENERGY INC	DEC	7,386.0 F	9,226.0 F	8,106.0 F	7,452.0 F	8,450.0 F	8,785.0 F	9,722.0 D,F	(2.7)	(3.4)	(19.9)	76	95	83	77	87
CMS	[] CMS ENERGY CORP	DEC	6,456.0 F	7,179.0 F	6,566.0 F	6,312.0 D,F	6,503.0 D,F	6,432.0 D,F	6,288.0 D,F	0.3	0.1	(10.1)	103	114	104	100	103
ED	[] CONSOLIDATED EDISON INC	DEC	12,554.0 F	12,919.0 F	12,354.0 F	12,188.0 F	12,938.0 F	13,325.0 F	11,690.0 D,F	0.7	(1.2)	(2.8)	107	111	106	104	111
D	[] DOMINION RESOURCES INC	DEC	11,683.0 F	12,436.0 F	13,120.0 D,F	13,093.0 D,F	14,379.0 F	15,197.0 D,F	18,041.0 D,F	(4.3)	(5.1)	(6.1)	65	69	73	73	80
DTE	[] DTE ENERGY CO	DEC	10,337.0 A,F	12,301.0 F	9,661.0 F	8,791.0 D,F	8,897.0 F	8,557.0 F	9,022.0 D,F	1.4	3.9	(16.0)	115	136	107	97	99
MDU	† MDU RESOURCES GROUP INC	DEC	4,191.5 D,F	4,670.6 F	4,462.4 F	4,075.4 A,F	4,050.5 F	3,909.7 F	3,455.4 F	2.0	1.4	(10.3)	121	135	129	118	117
NI	[] NISOURCE INC	DEC	4,651.8 D,F	6,470.6 F	5,657.3 F	5,061.2 D,F	6,019.1 F	6,422.0 D,F	7,899.1 D,F	(5.2)	(6.2)	(28.1)	59	82	72	64	76
NWE	† NORTHWESTERN CORP	DEC	1,214.3 A	1,204.9 A	1,154.5 F	1,070.3 F	1,117.3 F	1,110.7 F	1,165.8 D,F	0.4	1.8	0.8	104	103	99	92	96
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	10,415.0 F	10,886.0 F	9,968.0 F	9,781.0 F	11,343.0 F	11,793.0 D,F	12,430.0 D,F	(1.8)	(2.5)	(4.3)	84	88	80	79	91
SCG	[] SCANA CORP	DEC	4,380.0 F	4,951.0 F	4,495.0 F	4,176.0 F	4,409.0 F	4,601.0 F	4,777.0 F	(0.9)	(1.0)	(11.5)	92	104	94	87	92
SRE	[] SEMPRA ENERGY	DEC	10,231.0 F	11,035.0 F	10,557.0 F	9,647.0 F	10,036.0 F	9,003.0 F	11,737.0 D,F	(1.4)	2.6	(7.3)	87	94	90	82	86
VVC	† VECTREN CORP	DEC	2,434.7 F	2,611.7 A,F	2,491.2 F	2,232.8 F	2,325.2 F	2,129.5 F	2,028.0 F	1.8	2.7	(6.8)	120	129	123	110	115
WEC	[] WEC ENERGY GROUP INC	DEC	5,926.1 FB	4,997.1 BB	4,519.0 BB	4,246.4 BB	4,486.4 BB	4,202.5 FY	3,815.5 FY	4.5	7.1	18.6	155	131	118	111	118

Note: Data as originally reported. CAGR-Compound annual growth rate. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600.
**Not calculated; data for base year or end year not available. A - This year's data reflect an acquisition or merger. B - This year's data reflect a major merger resulting in the formation of a new company. C - This year's data reflect an accounting change. D - Data exclude discontinued operations. E - Includes excise taxes. F - Includes other (nonoperating) income. G - Includes sale of leased depts. H - Some or all data are not available, due to a fiscal year change.

Net Income

Ticker	Company	Yr. End	Million $							CAGR (%)			Index Basis (2005 = 100)				
			2015	2014	2013	2012	2011	2010	2005	10-Yr.	5-Yr.	1-Yr.	2015	2014	2013	2012	2011
AEP																	
ALE	§ ALLETE INC	DEC	141.1	124.8	104.7	97.1	93.8	75.3	17.6	23.1	13.4	13.1	802	709	595	552	533
LNT	[] ALLIANT ENERGY CORP	DEC	390.9	395.7	382.1	340.8	320.6	308.0	75.1	17.9	4.9	(1.2)	521	527	509	454	427
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	1,763.4	1,634.0	1,480.0	1,259.0	1,573.0	1,214.0	1,036.0	5.5	7.8	7.9	170	158	143	122	152
DUK	[] DUKE ENERGY CORP	DEC	2,796.0	2,459.0	2,648.0	1,732.0	1,705.0	1,317.0	2,533.0	1.0	16.2	13.7	110	97	105	68	67
EIX	[] EDISON INTERNATIONAL	DEC	1,098.0	1,539.0	979.0	1,594.0	25.0	1,304.0	1,132.0	(0.3)	(3.4)	(28.7)	97	136	86	141	2
EE	§ EL PASO ELECTRIC CO	DEC	81.9	91.4	88.6	90.8	103.5	90.3	36.6	8.4	(1.9)	(10.4)	224	250	242	248	283
ETR	[] ENTERGY CORP	DEC	(156.7)	960.3	730.6	868.4	1,367.4	1,270.3	968.6	NM	NM	NM	(16)	99	75	90	141
ES	[] EVERSOURCE ENERGY	DEC	878.5	819.5	786.0	525.9	394.7	387.9	(223.7)	NM	17.8	7.2	NM	NM	NM	NM	NM
EXC	[] EXELON CORP	DEC	2,269.0	1,623.0	1,719.0	1,160.0	2,495.0	2,563.0	955.0	9.0	(2.4)	39.8	238	170	180	121	261
FE	[] FIRSTENERGY CORP	DEC	578.0	213.0	375.0	770.0	885.0	784.0	888.0	(4.2)	(5.9)	171.4	65	24	42	87	100
GXP	† GREAT PLAINS ENERGY INC	DEC	213.0	242.8	250.2	199.9	174.4	211.7	164.2	2.6	0.1	(12.3)	130	148	152	122	106
HE	† HAWAIIAN ELECTRIC INDS	DEC	161.8	170.2	163.4	140.5	140.1	115.4	129.3	2.3	7.0	(5.0)	125	132	126	109	108
IDA	† IDACORP INC	DEC	194.7	193.5	182.4	168.8	166.7	142.8	63.7	11.8	6.4	0.6	306	304	287	265	262
NEE	[] NEXTERA ENERGY INC	DEC	2,752.0	2,465.0	1,720.0	1,911.0	1,923.0	1,957.0	885.0	12.0	7.1	11.6	311	279	194	216	217
OGE	† OGE ENERGY CORP	DEC	271.3	395.8	387.6	355.0	342.9	295.3	166.1	5.0	(1.7)	(31.5)	163	238	233	214	206
PCG	[] PG&E CORP	DEC	888.0	1,450.0	828.0	830.0	858.0	1,113.0	904.0	(0.2)	(4.4)	(38.8)	98	160	92	92	95
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	437.3	397.6	406.1	387.4	328.2	330.4	223.2	7.0	5.8	10.0	196	178	182	174	147
PNM	† PNM RESOURCES INC	DEC	16.2	116.8	101.0	106.1	176.9	(44.7)	71.0	(13.8)	NM	(86.2)	23	164	142	149	249
PPL	[] PPL CORP	DEC	1,603.0	1,583.0	1,128.0	1,532.0	1,493.0	955.0	739.0	8.1	10.9	1.3	217	214	153	207	202
SO	[] SOUTHERN CO	DEC	2,421.0	2,031.0	1,710.0	2,415.0	2,268.0	2,040.0	1,621.0	4.1	3.5	19.2	149	125	105	149	140
WR	† WESTAR ENERGY INC	DEC	291.9	313.3	292.5	275.1	230.2	203.9	134.9	8.0	7.4	(6.8)	216	232	217	204	171
XEL	[] XCEL ENERGY INC	DEC	984.5	1,021.3	948.2	905.2	841.4	752.0	499.0	7.0	5.5	(3.6)	197	205	190	181	169
MULTI-UTILITIES																	
AEE	[] AMEREN CORP	DEC	579.0	587.0	512.0	(974.0)	519.0	139.0	641.0	(1.0)	33.0	(1.4)	90	92	80	(152)	81
AVA	§ AVISTA CORP	DEC	118.1	119.6	111.1	78.2	100.2	92.4	45.2	10.1	5.0	(1.3)	261	265	246	173	222
BKH	† BLACK HILLS CORP	DEC	(32.1)	130.9	115.8	88.5	40.4	68.7	35.8	NM	NM	NM	(90)	366	324	247	113
CNP	[] CENTERPOINT ENERGY INC	DEC	(692.0)	611.0	311.0	417.0	770.0	442.0	225.0	NM	NM	NM	(308)	272	138	185	342
CMS	[] CMS ENERGY CORP	DEC	523.0	477.0	452.0	375.0	413.0	363.0	(93.0)	NM	7.6	9.6	NM	NM	NM	NM	NM
ED	[] CONSOLIDATED EDISON INC	DEC	1,193.0	1,092.0	1,062.0	1,141.0	1,062.0	1,003.0	743.0	4.8	3.5	9.2	161	147	143	154	143
D	[] DOMINION RESOURCES INC	DEC	1,899.0	1,310.0	1,789.0	324.0	1,408.0	2,963.0	1,050.0	6.1	(8.5)	45.0	181	125	170	31	134
DTE	[] DTE ENERGY CO	DEC	727.0	905.0	661.0	666.0	711.0	630.0	576.0	2.4	2.9	(19.7)	126	157	115	116	123
MDU	† MDU RESOURCES GROUP INC	DEC	149.9	295.1	279.2	(14.3)	226.0	244.0	275.1	(5.9)	(9.3)	(49.2)	55	107	102	(5)	82
NI	[] NISOURCE INC	DEC	183.0	530.7	490.9	410.6	303.8	294.6	287.8	(4.4)	(9.1)	(65.5)	64	184	171	143	106
NWE	† NORTHWESTERN CORP	DEC	151.2	120.7	94.0	98.4	92.6	77.4	61.5	9.4	14.3	25.3	246	196	153	160	150
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	1,679.0	1,518.0	1,243.0	1,275.0	1,407.0	1,557.0	862.0	6.9	1.5	10.6	195	176	144	148	163
SCG	[] SCANA CORP	DEC	746.0	538.0	471.0	420.0	387.0	376.0	327.0	8.6	14.7	38.7	228	165	144	128	118
SRE	[] SEMPRA ENERGY	DEC	1,350.0	1,162.0	1,009.0	865.0	1,365.0	749.0	939.0	3.7	12.5	16.2	144	124	107	92	145
VVC	† VECTREN CORP	DEC	197.3	166.9	136.6	159.0	141.6	133.7	136.8	3.7	8.1	18.2	144	122	100	116	104
WEC	[] WEC ENERGY GROUP INC	DEC	640.3	588.3	577.4	546.3	512.8	454.4	303.6	7.7	7.1	8.8	211	194	190	180	169

Note: Data as originally reported. CAGR-Compound annual growth rate. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600.
**Not calculated; data for base year or end year not available.

			Return on Revenues (%)					Return on Assets (%)					Return on Equity (%)				
Ticker	Company	Yr. End	2015	2014	2013	2012	2011	2015	2014	2013	2012	2011	2015	2014	2013	2012	2011
ELECTRIC UTILITIES																	
ALE	§ ALLETE INC	DEC	9.5	11.0	10.3	10.1	10.1	3.0	3.2	3.1	3.2	3.4	8.2	8.5	8.2	8.5	9.1
LNT	[] ALLIANT ENERGY CORP	DEC	12.0	11.8	11.7	11.0	8.7	3.1	3.3	3.3	3.2	3.2	10.6	11.5	11.4	10.6	10.2
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	10.7	9.6	9.6	8.4	10.4	2.9	2.8	2.7	2.4	3.1	10.2	9.9	9.5	8.4	11.1
DUK	[] DUKE ENERGY CORP	DEC	11.9	10.3	10.8	8.8	11.7	2.3	2.1	2.3	2.0	2.8	6.9	6.0	6.4	5.4	7.5
EIX	[] EDISON INTERNATIONAL	DEC	9.5	11.5	7.8	13.4	0.2	2.0	2.9	1.9	3.3	NM	8.8	13.7	9.1	15.4	NM
EE	§ EL PASO ELECTRIC CO	DEC	9.6	10.0	9.9	10.7	11.3	2.6	3.1	3.2	3.6	4.3	8.2	9.5	10.0	11.5	13.2
ETR	[] ENTERGY CORP	DEC	NM	7.7	6.4	8.4	12.2	NM	2.1	1.6	2.0	3.4	NM	9.6	7.6	9.3	15.4
ES	[] EVERSOURCE ENERGY	DEC	11.0	10.6	10.8	8.4	8.8	2.9	2.8	2.8	2.4	2.6	8.6	8.4	8.3	7.9	10.1
EXC	[] EXELON CORP	DEC	7.7	5.9	6.9	4.9	13.2	2.5	1.9	2.2	1.7	4.6	9.4	7.2	7.8	6.5	17.9
FE	[] FIRSTENERGY CORP	DEC	3.8	1.4	2.5	5.0	5.4	1.1	0.4	0.7	1.6	2.2	4.7	1.7	2.9	5.8	8.1
GXP	† GREAT PLAINS ENERGY INC	DEC	8.5	9.5	10.2	8.7	7.5	2.0	2.4	2.6	2.1	1.9	5.8	6.8	7.3	6.3	5.9
HE	† HAWAIIAN ELECTRIC INDS	DEC	6.2	5.3	5.0	4.2	4.3	1.5	1.6	1.6	1.5	1.5	8.6	9.6	9.7	8.9	9.2
IDA	† IDACORP INC	DEC	15.3	15.1	14.6	15.6	16.2	3.3	3.5	3.4	3.3	3.5	9.7	10.2	10.1	9.9	10.5
NEE	[] NEXTERA ENERGY INC	DEC	15.7	14.5	11.4	13.4	12.5	3.5	3.4	2.6	3.1	3.5	13.0	13.0	10.1	12.3	13.1
OGE	† OGE ENERGY CORP	DEC	12.3	16.1	13.5	9.7	8.8	2.8	4.2	4.1	3.8	4.1	8.3	12.6	13.4	13.3	14.1
PCG	[] PG&E CORP	DEC	5.3	8.5	5.3	5.5	5.7	1.4	2.5	1.5	1.6	1.8	5.4	9.5	5.9	6.5	7.2
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	12.5	11.4	11.8	11.7	10.1	3.0	2.9	3.0	2.9	2.6	9.8	9.3	9.9	9.9	8.7
PNM	† PNM RESOURCES INC	DEC	1.1	8.1	7.3	7.9	10.4	0.3	2.1	1.8	2.0	3.4	0.9	6.8	6.1	6.6	11.3
PPL	[] PPL CORP	DEC	20.9	13.7	9.5	12.6	11.7	3.6	3.3	2.5	3.6	4.0	13.6	12.1	9.8	14.4	15.7
SO	[] SOUTHERN CO	DEC	13.8	11.0	10.0	14.6	12.8	3.2	2.9	2.6	3.8	3.9	11.7	10.1	8.8	13.1	13.0
WR	† WESTAR ENERGY INC	DEC	11.9	12.0	12.3	12.2	10.6	2.8	3.1	3.1	3.0	2.7	8.4	9.9	9.8	9.7	8.9
XEL	[] XCEL ENERGY INC	DEC	8.9	8.7	8.7	8.9	7.9	2.6	2.9	2.9	3.0	2.9	9.5	10.3	10.3	10.4	10.1
MULTI-UTILITIES																	
AEE	[] AMEREN CORP	DEC	9.5	9.7	8.8	NM	6.9	2.5	2.7	2.4	NM	2.2	8.5	8.9	7.8	NM	6.6
AVA	§ AVISTA CORP	DEC	8.0	8.1	6.9	5.1	6.2	2.5	2.6	2.6	1.8	2.5	7.8	8.6	8.7	6.4	8.7
BKH	† BLACK HILLS CORP	DEC	NM	9.4	9.1	7.5	3.2	NM	3.2	3.0	2.3	1.0	NM	9.8	9.1	7.2	3.5
CNP	[] CENTERPOINT ENERGY INC	DEC	NM	6.6	3.8	5.6	9.1	NM	2.7	1.4	1.9	3.7	NM	13.8	7.2	9.8	20.8
CMS	[] CMS ENERGY CORP	DEC	8.1	6.6	6.9	5.9	6.4	2.6	2.6	2.6	2.2	2.6	13.7	13.4	13.6	12.1	14.2
ED	[] CONSOLIDATED EDISON INC	DEC	9.5	8.5	8.6	9.4	8.2	2.7	2.6	2.6	2.8	2.8	9.3	8.8	8.8	9.8	9.3
D	[] DOMINION RESOURCES INC	DEC	16.3	10.5	13.6	2.5	9.8	3.4	2.5	3.7	0.7	3.2	15.7	11.3	16.1	2.9	12.0
DTE	[] DTE ENERGY CO	DEC	7.0	7.4	6.8	7.6	8.0	2.6	3.4	2.5	2.5	2.8	8.5	11.1	8.6	9.3	10.4
MDU	† MDU RESOURCES GROUP INC	DEC	3.6	6.3	6.3	NM	5.6	2.1	4.0	4.1	NM	3.5	5.4	9.9	10.2	NM	8.3
NI	[] NISOURCE INC	DEC	3.9	8.2	8.7	8.1	5.0	0.9	2.2	2.2	1.9	1.5	3.7	8.8	8.6	7.8	6.1
NWE	† NORTHWESTERN CORP	DEC	12.5	10.0	8.1	9.2	8.3	2.9	2.8	2.6	2.9	3.0	9.8	9.6	9.6	11.0	11.0
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	16.1	13.9	12.5	13.0	12.4	4.6	4.5	3.9	4.1	4.7	13.3	12.8	11.1	12.1	14.1
SCG	[] SCANA CORP	DEC	17.0	10.9	10.5	10.1	8.8	4.4	3.4	3.2	3.0	2.9	14.3	11.1	10.7	10.4	10.2
SRE	[] SEMPRA ENERGY	DEC	13.2	10.5	9.6	9.0	13.6	3.3	3.0	2.7	2.5	4.3	11.7	10.4	9.4	8.5	14.4
VVC	† VECTREN CORP	DEC	8.1	6.4	5.5	7.1	6.1	3.7	3.3	2.7	3.2	2.9	12.0	10.6	8.9	10.6	9.8
WEC	[] WEC ENERGY GROUP INC	DEC	10.8	11.8	12.8	12.9	11.4	2.9	3.9	4.0	3.9	3.8	9.8	13.6	13.8	13.5	13.2

Note: Data as originally reported. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600.

				Current Ratio					Debt / Capital Ratio (%)					Net Inc. as % of Oper. Revs.				
Ticker		Company	Yr. End	2015	2014	2013	2012	2011	2015	2014	2013	2012	2011	2015	2014	2013	2012	2011
ELECTRIC UTILITIES																		
ALE	§	ALLETE INC	DEC	1.3	1.0	1.3	1.0	1.7	46.3	44.2	44.6	43.7	44.3	9.5	11.0	10.3	10.1	10.1
LNT	[]	ALLIANT ENERGY CORP	DEC	0.6	0.9	0.7	1.0	1.0	47.3	49.8	46.1	48.4	45.7	12.0	11.8	11.7	11.0	8.7
AEP	[]	AMERICAN ELECTRIC POWER CO	DEC	0.6	0.6	0.7	0.7	0.6	37.7	37.3	39.4	39.3	40.1	10.7	9.6	9.6	8.4	10.4
DUK	[]	DUKE ENERGY CORP	DEC	0.7	1.0	1.2	1.0	1.2	41.5	40.5	41.5	41.2	37.8	11.9	10.3	10.8	8.8	11.7
EIX	[]	EDISON INTERNATIONAL	DEC	0.5	0.7	0.7	0.7	1.0	45.0	44.6	46.2	35.1	45.2	9.5	11.5	7.8	13.4	0.2
EE	§	EL PASO ELECTRIC CO	DEC	0.6	1.1	1.3	1.6	0.8	42.5	43.7	41.7	45.7	43.4	9.6	10.0	9.9	10.7	11.3
ETR	[]	ENTERGY CORP	DEC	1.3	1.1	1.0	0.9	0.7	42.0	38.9	39.1	39.8	36.4	-1.4	7.7	6.4	8.4	12.2
ES	[]	EVERSOURCE ENERGY	DEC	0.9	0.9	0.6	0.6	0.7	45.6	45.9	44.3	43.7	53.4	11.0	10.6	10.8	8.4	8.8
EXC	[]	EXELON CORP	DEC	1.7	1.4	1.3	1.3	1.1	37.9	35.8	33.8	35.5	34.8	7.7	5.9	6.9	4.9	13.2
FE	[]	FIRSTENERGY CORP	DEC	0.5	0.7	0.5	0.5	0.7	60.7	60.7	55.5	53.7	54.2	3.8	1.4	2.5	5.0	5.4
GXP	†	GREAT PLAINS ENERGY INC	DEC	0.7	0.7	1.0	0.5	0.4	42.9	41.9	43.3	38.8	42.2	8.5	9.5	10.2	8.7	7.5
HE	†	HAWAIIAN ELECTRIC INDS	DEC	NA	NA	NA	NA	NA	49.4	49.6	49.7	49.9	50.1	6.2	5.3	5.0	4.2	4.3
IDA	†	IDACORP INC	DEC	1.9	1.8	1.9	1.0	0.8	45.6	45.3	46.6	45.5	45.6	15.3	15.1	14.6	15.6	16.2
NEE	[]	NEXTERA ENERGY INC	DEC	0.7	0.7	0.6	0.6	0.7	54.2	55.0	57.1	59.1	58.2	15.7	14.5	11.4	13.4	12.5
OGE	†	OGE ENERGY CORP	DEC	0.8	1.2	0.6	0.6	0.7	44.3	45.9	30.8	37.6	39.3	12.3	16.1	13.5	9.7	8.8
PCG	[]	PG&E CORP	DEC	0.9	1.1	0.8	0.8	0.8	48.8	48.5	46.6	48.4	48.8	5.3	8.5	5.3	5.5	5.7
PNW	[]	PINNACLE WEST CAPITAL CORP	DEC	0.6	0.6	0.6	0.9	0.7	31.6	29.8	29.5	44.6	44.1	12.5	11.4	11.8	11.7	10.1
PNM	†	PNM RESOURCES INC	DEC	0.6	0.6	0.8	1.0	1.2	43.6	38.5	39.9	41.7	42.7	1.1	8.1	7.3	7.9	10.4
PPL	[]	PPL CORP	DEC	0.7	0.8	1.0	0.9	1.2	57.9	50.8	55.2	56.9	55.5	20.9	13.7	9.5	12.6	11.7
SO	[]	SOUTHERN CO	DEC	0.7	0.7	1.0	0.9	1.0	40.9	37.9	40.3	38.9	39.9	13.8	11.0	10.0	14.6	12.8
WR	†	WESTAR ENERGY INC	DEC	0.9	0.8	0.7	0.8	0.8	38.0	40.8	41.0	41.9	40.7	11.9	12.0	12.3	12.2	10.6
XEL	[]	XCEL ENERGY INC	DEC	0.7	0.8	0.9	0.9	0.8	42.4	41.6	42.1	43.1	41.3	8.9	8.7	8.7	8.9	7.9
MULTI-UTILITIES																		
AEE	[]	AMEREN CORP	DEC	0.9	0.9	0.8	1.4	1.3	38.4	36.1	35.7	40.8	36.8	9.5	9.7	8.8	-14.3	6.9
AVA	§	AVISTA CORP	DEC	0.6	1.0	0.9	0.9	1.0	50.0	51.0	51.1	50.7	50.3	8.0	8.1	6.9	5.1	6.2
BKH	†	BLACK HILLS CORP	DEC	1.9	0.7	0.9	0.6	0.9	56.0	48.4	51.6	43.2	51.4	-2.5	9.4	9.1	7.5	3.2
CNP	[]	CENTERPOINT ENERGY INC	DEC	1.1	0.9	0.9	0.8	0.9	48.2	46.3	46.8	66.0	67.2	-9.4	6.6	3.8	5.6	9.1
CMS	[]	CMS ENERGY CORP	DEC	1.0	1.3	1.3	1.3	1.1	58.6	60.0	58.4	61.5	59.9	8.1	6.6	6.9	5.9	6.4
ED	[]	CONSOLIDATED EDISON INC	DEC	0.8	1.0	0.8	0.9	1.2	34.7	34.9	33.6	33.2	34.6	9.5	8.5	8.6	9.4	8.2
D	[]	DOMINION RESOURCES INC	DEC	0.5	0.8	0.8	0.7	0.8	65.1	65.4	61.9	60.9	59.8	16.3	10.5	13.6	2.5	9.8
DTE	[]	DTE ENERGY CO	DEC	1.0	1.2	0.9	1.1	1.2	40.9	40.7	39.0	39.8	41.4	7.0	7.4	6.8	7.6	8.0
MDU	†	MDU RESOURCES GROUP INC	DEC	1.1	1.2	1.4	1.3	1.3	40.4	36.8	39.5	37.8	31.7	3.6	6.3	6.3	-0.4	5.6
NI	[]	NISOURCE INC	DEC	0.6	0.6	0.7	0.7	0.6	48.9	45.3	45.3	44.4	45.3	3.9	8.2	8.7	8.1	5.0
NWE	†	NORTHWESTERN CORP	DEC	0.5	0.6	0.7	0.7	0.6	53.1	53.4	53.5	53.8	52.2	12.5	10.0	8.1	9.2	8.3
PEG	[]	PUBLIC SERVICE ENTRP GRP INC	DEC	1.0	1.2	1.2	1.0	1.3	29.4	29.8	29.6	27.9	32.2	16.1	13.9	12.5	13.0	12.4
SCG	[]	SCANA CORP	DEC	0.7	0.8	1.0	0.8	0.9	44.5	44.6	45.7	45.9	45.8	17.0	10.9	10.5	10.1	8.8
SRE	[]	SEMPRA ENERGY	DEC	0.6	0.8	0.9	0.9	0.6	46.7	45.8	44.8	48.1	46.6	13.2	10.5	9.6	9.0	13.6
VVC	†	VECTREN CORP	DEC	1.2	0.9	1.2	0.9	0.9	40.9	37.4	43.9	41.8	43.3	8.1	6.4	5.5	7.1	6.1
WEC	[]	WEC ENERGY GROUP INC	DEC	0.8	0.9	1.0	0.9	1.0	51.2	48.5	50.6	51.7	53.6	10.8	11.8	12.8	12.9	11.4

Note: Data as originally reported. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600.

Ticker	Company	Yr. End	Price / Earnings Ratio (High-Low)					Dividend Payout Ratio (%)					Dividend Yield (High-Low, %)				
			2015	2014	2013	2012	2011	2015	2014	2013	2012	2011	2015	2014	2013	2012	2011
ELECTRIC UTILITIES																	
ALE	§ ALLETE INC	DEC	20 - 16	20 - 15	21 - 16	16 - 15	16 - 13	69	67	72	71	67	4.5 - 3.4	4.4 - 3.4	4.6 - 3.5	4.9 - 4.3	5.1 - 4.2
LNT	[] ALLIANT ENERGY CORP	DEC	21 - 16	20 - 14	16 - 13	16 - 14	16 - 12	65	59	57	61	62	4.1 - 3.1	4.1 - 2.9	4.3 - 3.5	4.3 - 3.8	5.0 - 3.8
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	18 - 15	19 - 14	17 - 14	17 - 14	13 - 10	60	61	64	72	57	4.1 - 3.3	4.4 - 3.2	4.7 - 3.8	5.1 - 4.1	5.6 - 4.4
DUK	[] DUKE ENERGY CORP	DEC	22 - 16	25 - 19	20 - 17	24 - 20	17 - 13	81	91	83	101	77	4.9 - 3.6	4.7 - 3.6	4.8 - 4.1	5.1 - 4.3	5.9 - 4.5
EIX	[] EDISON INTERNATIONAL	DEC	23 - 18	16 - 10	20 - 16	10 - 9	NM - NM	57	34	51	28	NM	3.1 - 2.5	3.3 - 2.2	3.1 - 2.5	3.3 - 2.7	3.9 - 3.1
EE	§ EL PASO ELECTRIC CO	DEC	20 - 17	19 - 15	18 - 14	16 - 13	14 - 11	57	49	47	43	27	3.4 - 2.8	3.3 - 2.6	3.3 - 2.7	3.3 - 2.7	2.5 - 1.8
ETR	[] ENTERGY CORP	DEC	NM - NM	18 - 12	18 - 15	16 - 13	10 - 8	NM	63	83	70	44	5.5 - 3.7	5.5 - 3.6	5.5 - 4.6	5.4 - 4.5	5.8 - 4.5
ES	[] EVERSOURCE ENERGY	DEC	21 - 16	22 - 16	18 - 16	22 - 18	16 - 14	60	61	59	70	50	3.7 - 2.9	3.8 - 2.8	3.8 - 3.2	4.0 - 3.2	3.7 - 3.0
EXC	[] EXELON CORP	DEC	15 - 10	21 - 14	19 - 13	31 - 20	12 - 10	49	66	72	148	56	4.9 - 3.2	4.7 - 3.2	5.5 - 3.8	7.4 - 4.8	5.4 - 4.6
FE	[] FIRSTENERGY CORP	DEC	30 - 21	80 - 59	52 - 35	28 - 22	21 - 16	105	282	244	119	99	5.0 - 3.5	4.8 - 3.5	7.0 - 4.7	5.4 - 4.3	6.1 - 4.7
GXP	† GREAT PLAINS ENERGY INC	DEC	22 - 18	19 - 15	15 - 13	17 - 14	17 - 13	73	60	54	63	66	4.1 - 3.3	3.9 - 3.2	4.3 - 3.5	4.4 - 3.7	5.1 - 3.8
HE	† HAWAIIAN ELECTRIC INDS	DEC	23 - 18	21 - 14	17 - 15	20 - 17	18 - 14	83	75	76	87	86	4.6 - 3.6	5.5 - 3.5	5.2 - 4.4	5.2 - 4.2	6.0 - 4.6
IDA	† IDACORP INC	DEC	18 - 14	18 - 13	15 - 12	14 - 11	13 - 10	49	46	43	41	36	3.5 - 2.7	3.5 - 2.5	3.6 - 2.9	3.6 - 3.0	3.5 - 2.8
NEE	[] NEXTERA ENERGY INC	DEC	18 - 15	20 - 15	22 - 17	16 - 13	13 - 11	50	51	65	52	48	3.3 - 2.7	3.5 - 2.6	3.8 - 2.9	4.1 - 3.3	4.5 - 3.6
OGE	† OGE ENERGY CORP	DEC	27 - 18	20 - 17	20 - 14	17 - 14	16 - 12	75	46	43	44	43	4.2 - 2.8	2.8 - 2.4	3.0 - 2.1	3.1 - 2.6	3.7 - 2.6
PCG	[] PG&E CORP	DEC	33 - 26	18 - 13	27 - 22	24 - 21	23 - 18	101	59	99	95	87	3.8 - 3.0	4.6 - 3.3	4.6 - 3.8	4.6 - 3.9	4.9 - 3.8
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	19 - 14	20 - 14	17 - 14	15 - 13	16 - 12	61	64	60	60	70	4.3 - 3.3	4.5 - 3.2	4.3 - 3.6	4.6 - 3.9	5.6 - 4.3
PNM	† PNM RESOURCES INC	DEC	NM - NM	22 - 16	19 - 16	17 - 13	10 - 6	400	51	51	42	25	3.3 - 2.6	3.1 - 2.3	3.2 - 2.6	3.2 - 2.5	3.9 - 2.6
PPL	[] PPL CORP	DEC	15 - 12	16 - 12	18 - 15	12 - 10	11 - 9	63	62	79	55	52	5.1 - 4.1	5.1 - 3.9	5.2 - 4.4	5.4 - 4.8	5.8 - 4.6
SO	[] SOUTHERN CO	DEC	20 - 16	23 - 18	26 - 21	18 - 15	18 - 14	83	95	107	72	73	5.2 - 4.0	5.2 - 4.1	5.0 - 4.1	4.7 - 4.0	5.2 - 4.0
WR	† WESTAR ENERGY INC	DEC	21 - 16	18 - 13	15 - 12	15 - 12	15 - 12	68	58	59	61	66	4.3 - 3.3	4.4 - 3.2	4.8 - 3.9	4.9 - 4.0	5.7 - 4.4
XEL	[] XCEL ENERGY INC	DEC	20 - 16	19 - 13	17 - 14	16 - 14	16 - 12	66	59	58	58	60	4.0 - 3.3	4.4 - 3.2	4.1 - 3.5	4.1 - 3.6	4.9 - 3.7
MULTI-UTILITIES																	
AEE	[] AMEREN CORP	DEC	20 - 16	20 - 15	18 - 15	NM - NM	16 - 12	69	67	76	NM	72	4.4 - 3.5	4.6 - 3.3	5.2 - 4.3	5.6 - 4.5	6.1 - 4.6
AVA	§ AVISTA CORP	DEC	20 - 16	19 - 14	16 - 13	21 - 17	15 - 12	69	65	66	88	64	4.4 - 3.4	4.6 - 3.4	5.1 - 4.2	5.1 - 4.1	5.2 - 4.1
BKH	† BLACK HILLS CORP	DEC	NM - NM	21 - 16	21 - 14	18 - 15	35 - 26	NM	53	58	73	145	4.4 - 3.0	3.3 - 2.5	4.1 - 2.8	4.9 - 4.0	5.7 - 4.2
CNP	[] CENTERPOINT ENERGY INC	DEC	NM - NM	18 - 15	35 - 26	22 - 18	12 - 8	NM	67	114	83	44	6.2 - 4.2	4.5 - 3.7	4.3 - 3.2	4.5 - 3.7	5.2 - 3.7
CMS	[] CMS ENERGY CORP	DEC	20 - 16	21 - 15	18 - 14	17 - 15	14 - 10	61	61	60	67	51	3.7 - 3.0	4.2 - 2.9	4.1 - 3.4	4.5 - 3.8	5.0 - 3.8
ED	[] CONSOLIDATED EDISON INC	DEC	18 - 14	18 - 14	18 - 15	17 - 14	17 - 14	64	68	68	62	67	4.6 - 3.6	4.8 - 3.7	4.5 - 3.8	4.5 - 3.7	4.9 - 3.8
D	[] DOMINION RESOURCES INC	DEC	25 - 20	36 - 28	22 - 17	98 - 86	22 - 17	81	107	73	370	80	4.0 - 3.2	3.8 - 3.0	4.3 - 3.3	4.3 - 3.8	4.7 - 3.7
DTE	[] DTE ENERGY CO	DEC	23 - 18	18 - 13	19 - 16	16 - 13	13 - 10	70	53	69	62	55	3.9 - 3.1	4.1 - 3.0	4.3 - 3.5	4.6 - 3.9	5.4 - 4.2
MDU	† MDU RESOURCES GROUP INC	DEC	32 - 21	24 - 14	21 - 15	NM - NM	20 - 15	95	47	47	NM	55	4.6 - 3.0	3.4 - 2.0	3.2 - 2.2	3.4 - 2.9	3.6 - 2.7
NI	[] NISOURCE INC	DEC	85 - 28	27 - 19	21 - 16	19 - 16	22 - 16	143	61	62	67	85	5.2 - 1.7	3.2 - 2.3	3.9 - 2.9	4.2 - 3.6	5.2 - 3.8
NWE	† NORTHWESTERN CORP	DEC	19 - 15	20 - 14	19 - 14	14 - 12	14 - 11	60	53	62	55	56	4.0 - 3.2	3.8 - 2.7	4.3 - 3.2	4.5 - 3.9	5.3 - 3.9
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	13 - 11	15 - 10	15 - 12	14 - 11	13 - 10	47	49	59	56	49	4.2 - 3.5	4.7 - 3.4	4.8 - 3.9	4.9 - 4.2	4.9 - 3.9
SCG	[] SCANA CORP	DEC	13 - 10	17 - 12	16 - 13	16 - 14	15 - 12	42	55	60	62	64	4.4 - 3.3	4.6 - 3.3	4.5 - 3.7	4.6 - 3.9	5.6 - 4.3
SRE	[] SEMPRA ENERGY	DEC	21 - 16	25 - 18	23 - 17	20 - 15	10 - 8	52	56	61	67	34	3.1 - 2.4	3.0 - 2.3	3.6 - 2.7	4.4 - 3.3	4.3 - 3.4
VVC	† VECTREN CORP	DEC	21 - 16	24 - 17	23 - 18	16 - 14	18 - 14	64	72	86	72	80	4.1 - 3.1	4.2 - 3.0	4.8 - 3.8	5.1 - 4.6	5.9 - 4.5
WEC	[] WEC ENERGY GROUP INC	DEC	25 - 19	21 - 15	18 - 15	18 - 14	16 - 12	74	60	57	51	47	3.9 - 3.0	3.9 - 2.8	3.9 - 3.2	3.6 - 2.9	3.9 - 2.9

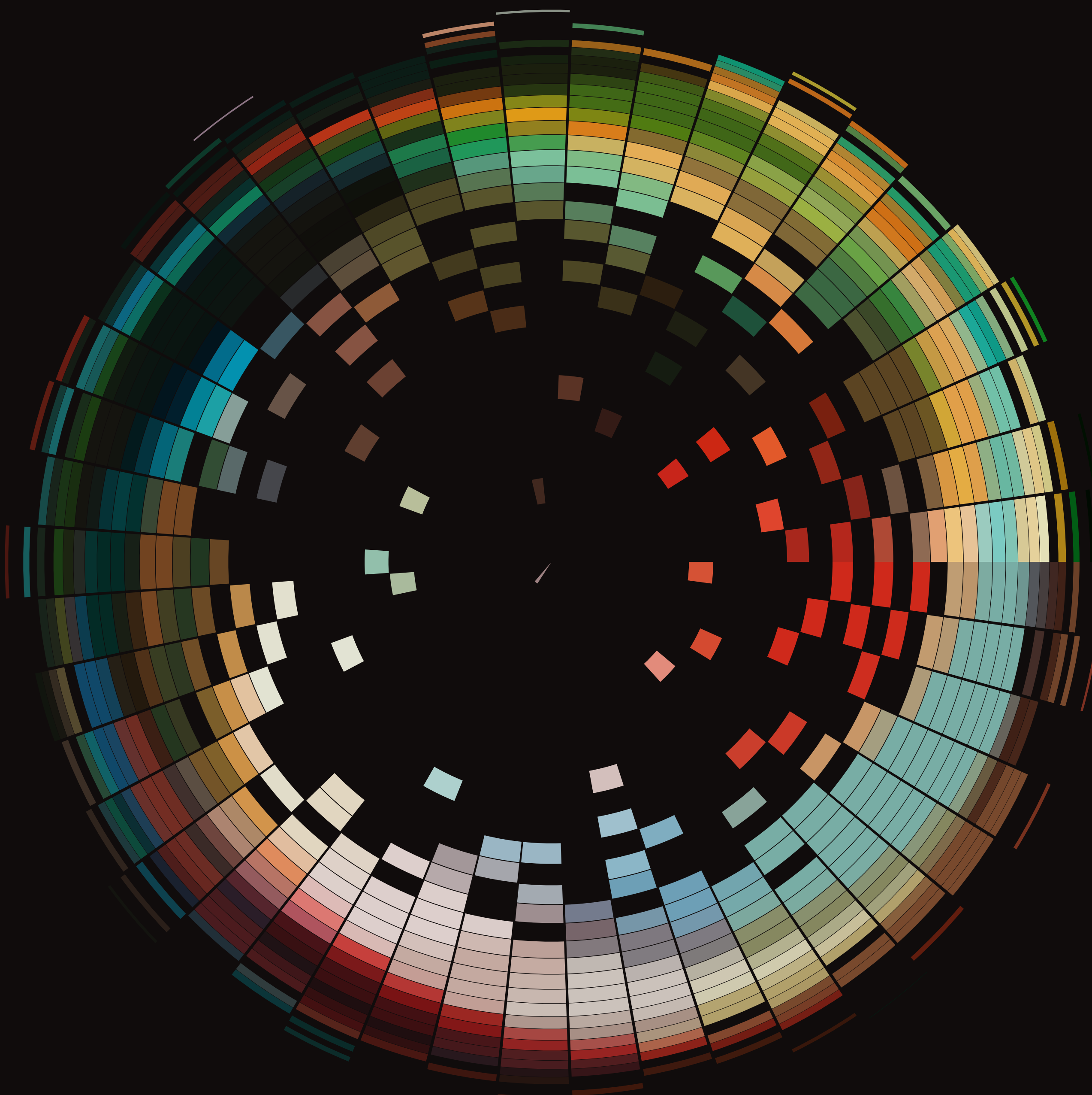
Note: Data as originally reported. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600.

Ticker		Company	Yr. End	Earnings per Share ($) 2015	2014	2013	2012	2011	Tangible Book Value per Share ($) 2015	2014	2013	2012	2011	Share Price (High-Low, $) 2015	2014	2013	2012	2011
ELECTRIC UTILITIES																		
ALE	§	ALLETE INC	DEC	2.92	2.91	2.64	2.59	2.66	32.71	35.04	32.44	30.48	28.78	59.73 - 45.29	57.97 - 44.19	54.13 - 41.39	42.66 - 37.73	42.54 - 35.14
LNT	[]	ALLIANT ENERGY CORP	DEC	1.69	1.74	1.64	1.47	1.37	16.41	15.50	14.79	14.12	13.57	35.40 - 27.14	34.89 - 25.00	27.09 - 21.86	23.83 - 20.93	22.25 - 16.95
AEP	[]	AMERICAN ELECTRIC POWER CO	DEC	3.59	3.34	3.04	2.60	3.25	36.32	34.17	32.77	31.14	30.18	65.38 - 52.29	63.22 - 45.80	51.60 - 41.83	45.41 - 36.97	41.71 - 33.09
DUK	[]	DUKE ENERGY CORP	DEC	4.02	3.46	3.74	3.01	3.84	33.57	34.36	34.86	34.27	41.68	89.97 - 65.50	87.29 - 67.05	75.46 - 64.16	71.14 - 59.63	66.37 - 50.62
EIX	[]	EDISON INTERNATIONAL	DEC	3.02	4.38	2.70	4.61	(0.10)	34.89 J	33.64 J	30.50 J	28.95 J	30.86 J	69.59 - 55.18	68.74 - 44.74	54.19 - 44.26	47.96 - 39.60	41.57 - 32.64
EE	§	EL PASO ELECTRIC CO	DEC	2.03	2.27	2.20	2.27	2.49	25.21	24.46	23.51	20.61	19.10	41.32 - 33.77	42.17 - 33.44	39.12 - 31.84	35.34 - 29.17	35.71 - 26.65
ETR	[]	ENTERGY CORP	DEC	(0.99)	5.24	3.99	4.77	7.59	49.78	53.73	51.89	49.60	48.67	90.33 - 61.27	92.02 - 60.40	72.60 - 60.22	74.50 - 61.55	74.50 - 57.60
ES	[]	EVERSOURCE ENERGY	DEC	2.77	2.59	2.49	1.90	2.22	21.54	20.37	19.32	18.21	21.03	56.83 - 44.64	56.66 - 41.28	45.66 - 38.60	40.86 - 33.48	36.47 - 30.02
EXC	[]	EXELON CORP	DEC	2.55	1.89	2.01	1.42	3.76	25.13	23.19	23.45	22.00	17.73	38.25 - 25.09	38.93 - 26.45	37.80 - 26.64	43.70 - 28.40	45.45 - 39.06
FE	[]	FIRSTENERGY CORP	DEC	1.37	0.51	0.90	1.85	2.22	13.39	13.08	13.58	14.19	16.35	41.68 - 28.89	40.84 - 29.98	46.77 - 31.29	51.14 - 40.37	46.51 - 36.11
GXP	†	GREAT PLAINS ENERGY INC	DEC	1.37	1.57	1.62	1.36	1.27	22.59	22.17	21.48	20.65	20.50	30.25 - 24.06	29.46 - 23.75	24.88 - 20.39	22.85 - 19.45	22.09 - 16.34
HE	†	HAWAIIAN ELECTRIC INDS	DEC	1.50	1.65	1.63	1.43	1.45	17.17	16.66	16.24	15.44	15.10	34.86 - 27.02	35.00 - 22.70	28.30 - 23.84	29.24 - 23.65	26.79 - 20.59
IDA	†	IDACORP INC	DEC	3.88	3.86	3.64	3.38	3.37	40.65	38.58	36.53	34.71	32.78	70.48 - 55.40	70.05 - 50.21	54.74 - 43.13	45.67 - 38.17	42.66 - 33.88
NEE	[]	NEXTERA ENERGY INC	DEC	6.11	5.67	4.06	4.59	4.62	48.97 J	44.96 J	41.47 J	37.90 J	35.92 J	112.64 - 93.74	110.84 - 83.97	89.75 - 69.81	72.22 - 58.57	61.20 - 49.00
OGE	†	OGE ENERGY CORP	DEC	1.36	1.99	1.96	1.80	1.75	16.65	16.27	15.30	13.16	12.17	36.47 - 24.15	39.28 - 32.85	40.00 - 27.69	30.10 - 25.11	28.58 - 20.28
PCG	[]	PG&E CORP	DEC	1.81	3.07	1.83	1.92	2.10	33.69 J	33.09 J	31.41 J	30.21	29.20	60.21 - 47.33	55.24 - 39.42	48.50 - 39.91	47.03 - 39.40	47.99 - 36.84
PNW	[]	PINNACLE WEST CAPITAL CORP	DEC	3.94	3.59	3.69	3.54	3.01	41.30 J	39.50 J	38.07 J	36.20 J	33.42	73.31 - 56.01	71.11 - 51.15	61.89 - 51.50	54.66 - 45.95	48.87 - 37.28
PNM	†	PNM RESOURCES INC	DEC	0.20	1.46	1.26	1.32	1.98	17.28	18.12	17.52	16.70	16.27	31.23 - 24.42	31.60 - 23.53	24.53 - 20.06	22.54 - 17.29	19.17 - 12.75
PPL	[]	PPL CORP	DEC	2.38	2.41	1.85	2.62	2.70	8.44	13.06	11.57	9.27	9.77	36.74 - 29.18	38.14 - 29.40	33.55 - 28.44	30.18 - 26.68	30.27 - 24.10
SO	[]	SOUTHERN CO	DEC	2.60	2.19	1.88	2.70	2.57	22.59 J	21.98 J	21.43 J	21.09 J	20.32 J	53.16 - 41.40	51.28 - 40.27	48.74 - 40.03	48.59 - 41.75	46.69 - 35.73
WR	†	WESTAR ENERGY INC	DEC	2.11	2.40	2.29	2.15	1.95	25.87 J	25.02 J	23.88 J	22.89 J	22.03 J	44.03 - 33.88	43.15 - 31.67	34.96 - 28.59	33.04 - 26.80	29.05 - 22.63
XEL	[]	XCEL ENERGY INC	DEC	1.94	2.03	1.91	1.86	1.72	20.89 J	20.20 J	19.21 J	18.19 J	17.44 J	38.35 - 31.76	37.58 - 27.27	31.79 - 26.77	29.92 - 25.84	27.78 - 21.20
MULTI-UTILITIES																		
AEE	[]	AMEREN CORP	DEC	2.39	2.42	2.11	(4.01)	2.15	26.94	25.98	25.19	25.51	30.92	46.81 - 37.26	48.14 - 35.22	37.31 - 30.64	35.30 - 28.43	34.10 - 25.55
AVA	§	AVISTA CORP	DEC	1.90	1.94	1.85	1.32	1.73	23.61	22.91	19.68	19.01	19.03	38.34 - 29.77	37.37 - 27.71	29.26 - 24.10	28.05 - 22.78	26.53 - 21.13
BKH	†	BLACK HILLS CORP	DEC	(0.71)	2.95	2.62	2.02	1.01	21.54	22.33	21.37	19.80	19.40	53.37 - 36.81	62.13 - 47.11	55.09 - 36.89	37.00 - 30.29	34.85 - 25.83
CNP	[]	CENTERPOINT ENERGY INC	DEC	(1.61)	1.42	0.73	0.98	1.81	6.10	8.62	8.13	6.62	5.93	23.66 - 16.05	25.75 - 21.07	25.65 - 19.33	21.81 - 18.07	21.47 - 15.09
CMS	[]	CMS ENERGY CORP	DEC	1.90	1.76	1.71	1.43	1.65	14.21	13.34	12.98	12.10	11.92	38.65 - 31.22	36.87 - 25.95	29.98 - 24.60	24.98 - 21.12	22.37 - 16.96
ED	[]	CONSOLIDATED EDISON INC	DEC	4.07	3.73	3.62	3.88	3.59	43.08	41.46	40.33	39.05	37.57	72.25 - 56.86	68.92 - 52.23	64.03 - 54.17	65.98 - 53.63	62.74 - 48.55
D	[]	DOMINION RESOURCES INC	DEC	3.21	2.25	3.09	0.57	2.46	14.77	13.57	13.76	11.98	13.45	79.89 - 64.54	80.89 - 63.14	67.97 - 51.92	55.62 - 48.87	53.59 - 42.06
DTE	[]	DTE ENERGY CO	DEC	4.05	5.11	3.76	3.89	4.19	37.14	35.07	32.64	30.29	29.05	92.27 - 73.23	90.77 - 64.84	73.32 - 60.33	62.56 - 52.46	55.28 - 43.22
MDU	†	MDU RESOURCES GROUP INC	DEC	0.77	1.53	1.47	(0.08)	1.19	8.91	12.74	11.40	10.49	11.15	24.51 - 16.15	36.05 - 21.33	30.97 - 21.50	23.21 - 19.59	24.05 - 18.00
NI	[]	NISOURCE INC	DEC	0.58	1.68	1.57	1.41	1.08	5.95	7.10	6.20	5.13	3.63	49.16 - 16.03	44.91 - 32.11	33.48 - 24.85	26.15 - 22.32	23.97 - 17.71
NWE	†	NORTHWESTERN CORP	DEC	3.20	3.01	2.46	2.67	2.55	25.79	23.93	17.44	15.55	13.89	59.71 - 48.44	58.70 - 42.64	47.18 - 35.06	37.96 - 32.98	36.61 - 27.38
PEG	[]	PUBLIC SERVICE ENTRP GRP INC	DEC	3.32	3.00	2.46	2.52	2.78	25.63	23.89	22.85	21.21	20.01	44.45 - 36.80	43.77 - 31.25	37.00 - 29.70	34.07 - 28.92	35.48 - 27.97
SCG	[]	SCANA CORP	DEC	5.22	3.79	3.40	3.20	3.01	38.09	34.95	33.08	31.47	29.92	65.57 - 49.89	63.41 - 45.58	54.41 - 44.75	50.34 - 43.32	45.48 - 34.64
SRE	[]	SEMPRA ENERGY	DEC	5.43	4.72	4.10	3.56	5.66	42.63	40.51	39.10	36.04	34.82	116.21 - 89.44	116.30 - 86.73	93.00 - 70.61	72.87 - 54.69	55.97 - 44.78
VVC	†	VECTREN CORP	DEC	2.39	2.02	1.66	1.94	1.73	16.67	15.50	15.36	15.37	14.69	49.47 - 37.26	48.28 - 34.60	37.88 - 29.47	30.75 - 27.46	30.65 - 23.65
WEC	[]	WEC ENERGY GROUP INC	DEC	2.36	2.61	2.54	2.37	2.20	17.84	17.64	16.78	16.12	15.28	58.01 - 44.93	55.39 - 40.17	45.00 - 37.03	41.48 - 33.62	35.38 - 27.00

Note: Data as originally reported. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. J-This amount includes intangibles that cannot be identified.

Disclosure

Deloitte.



From growth to modernization

The changing capital focus of the US utility sector

Executive summary

In Deloitte's "math series," published from 2012-2014, we analyzed the trends prompting US electric power companies to increase capital spending and examined the "dilemma" they could face as the costs to produce electricity rise, while demand remains fairly stagnant.[1] Since then, as these trends have played out, spending has predictably climbed to unprecedented levels. US electric and gas utility capital expenditures soared from $69 billion in 2008, to an all-time high estimated for 2016—about $115 billion.[2] Drivers behind the spending vary and include:

- The need to upgrade and reinforce electric and gas infrastructure due to age, increasingly severe weather, and cyber and physical threats
- The equally critical need to deploy information technology to boost the systems' efficiency, effectiveness, and resilience; accommodate the surge of new technologies and devices; and respond to customer demand for more flexible and customized products
- The need to address environmental concerns with an increasingly clean energy slate
- The opportunity to take advantage of burgeoning supplies of domestic natural gas

In addition, the quest for predictable growth in earnings may be shifting the focus back to regulated investments with relatively stable rates of return.

These drivers are evolving and changing the pattern of investment across individual companies and the industry as a whole. The group of electric and gas utility companies examined in this report generally project capital spending plans across five segments: electric transmission and distribution (T&D), generation; environmental; renewables; and natural gas pipelines, distribution, and storage.* Electric T&D spending has dominated the mix in recent years, and will likely grow further. At the same time, generation investments are projected to ramp down, while expenditures on natural gas pipelines, storage, and distribution are slated to continue to grow. Overall, company projections indicate that capital expenditures will likely remain substantial, which is not surprising, since key drivers behind the spending continue.

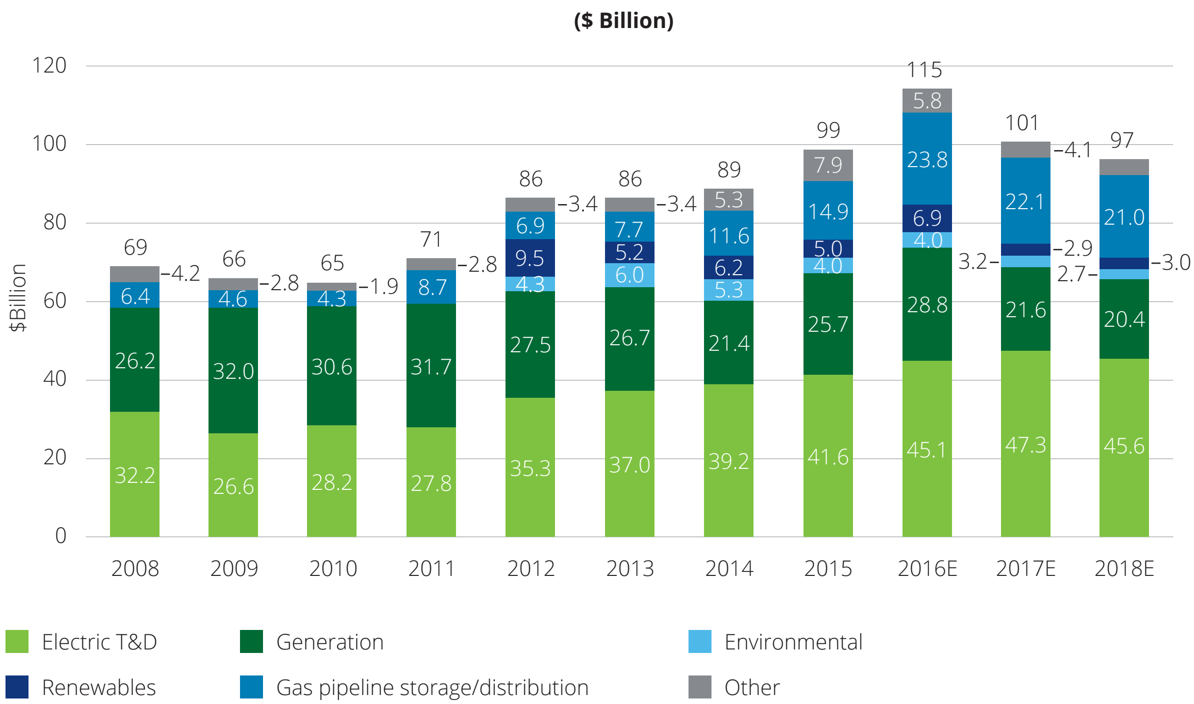
So, the question arises whether spending at today's levels can be sustained. Rapidly rising expenditures are beginning to boost retail electricity rates, and while much of the cost is being offset by lower fuel costs thanks to abundant, moderately priced shale gas, the specter of potentially rising natural gas prices, increasing interest rates, higher taxes, or a host of other possibilities could intervene to alter capital investment momentum.

*Electric power industry subsectors that do not segment expenditures similarly, such as alternative energy developers and retail energy providers, were not included in the analysis, since comparisons would not be consistent.

A decade of growth in utility capital spending

In Figure 1, we see the aggregate capital spending for a representative group of publicly traded electric and gas companies—laddering up each year from 2010 to the present, and projected to remain substantial as the new decade approaches.

Figure 1. Capex breakdown by category for 47 investor-owned electric and gas utilities—Historical and projected (2008-2018E)



Note: Historical segmentation prior to 2008 is not available

Source: RRA and SNL Energy, Deloitte analysis. RRA and SNL Energy are offerings of S&P Global Market Intelligence.

Methodology – The data shown in Figures 1 and 2 is based on SNL Energy's RRA Index of the largest publicly traded US electric and gas companies, including regulated, merchant, and hybrid enterprises. This includes electric companies with more than 400,000 customers and gas companies with more than 900,000. The resulting universe of 47 companies covers roughly 89% of the current total market capitalization of the 84 companies in these categories.

Most of the companies segment their capital expenditures by category in projections and in estimates for the current year, but do not do so when reporting final expenditures at yearend. Therefore, to derive the historical segmentation in Figures 1 and 2, we extrapolated the companies' projected breakdowns across the final amount expended. This may not be an exact reflection of historical spending, but it is likely a strong indicator. In addition, periodic changes to the index occur as companies are added or subtracted due to restructuring; consequently, historical comparisons are not exact.

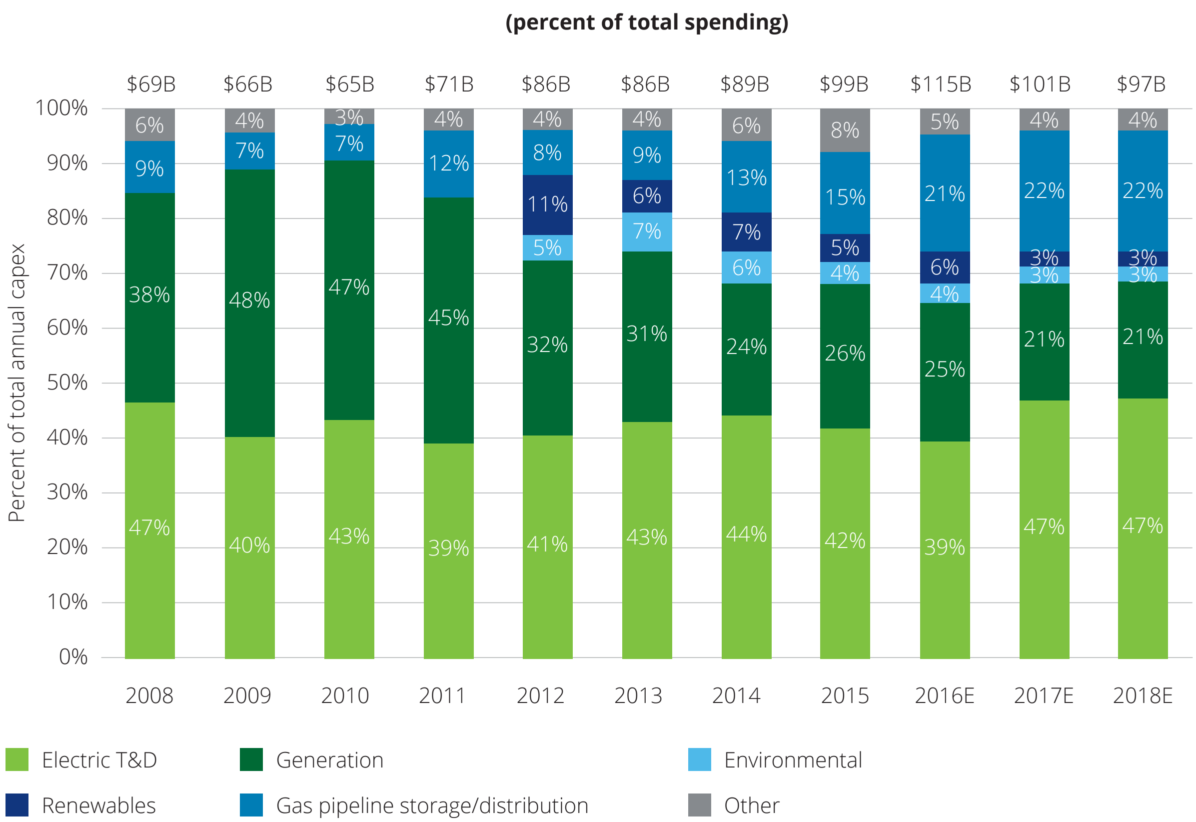
Finally, some companies began projecting environmental and renewable expenditures separately in 2012. For others, and for all companies before 2012, these expenditures are typically included in the generation category.

In the breakdown by percentage of total spending shown in Figure 2, we see a rising proportion of spending on electric T&D and natural gas infrastructure. Drivers behind this are discussed in the following sections, but one point to note is that investments in both of these segments are usually regulated, and electric and gas companies appear to be pivoting strategically toward regulated investments. According to Edison Electric Institute (EEI), the trade association for investor-owned electric utilities, from 2002-2014 its members moved from a balance sheet that was roughly 60 percent regulated to one that is closer to 75 percent regulated.[3]

Transmission and distribution spending takes center stage as utilities upgrade infrastructure

T&D, the top spending category, accounted for nearly 43 percent of annual capital expenditures from 2008-2015, and reached about $42 billion in 2015. Company projections indicate that share will likely rise to 47 percent in 2017 and 2018 (see Figure 2).[4] Likewise, EEI recently reported their member companies' spending on T&D "is expected to increase steadily in relative importance over the next few years."[5] And this is despite slow electricity demand (load) growth, with a compound annual growth rate of just 0.9 percent projected for the US from 2015-2040.[6]

Figure 2. Capex breakdown by category for 47 investor-owned electric and gas utilities—Historical and projected (2008-2018E)

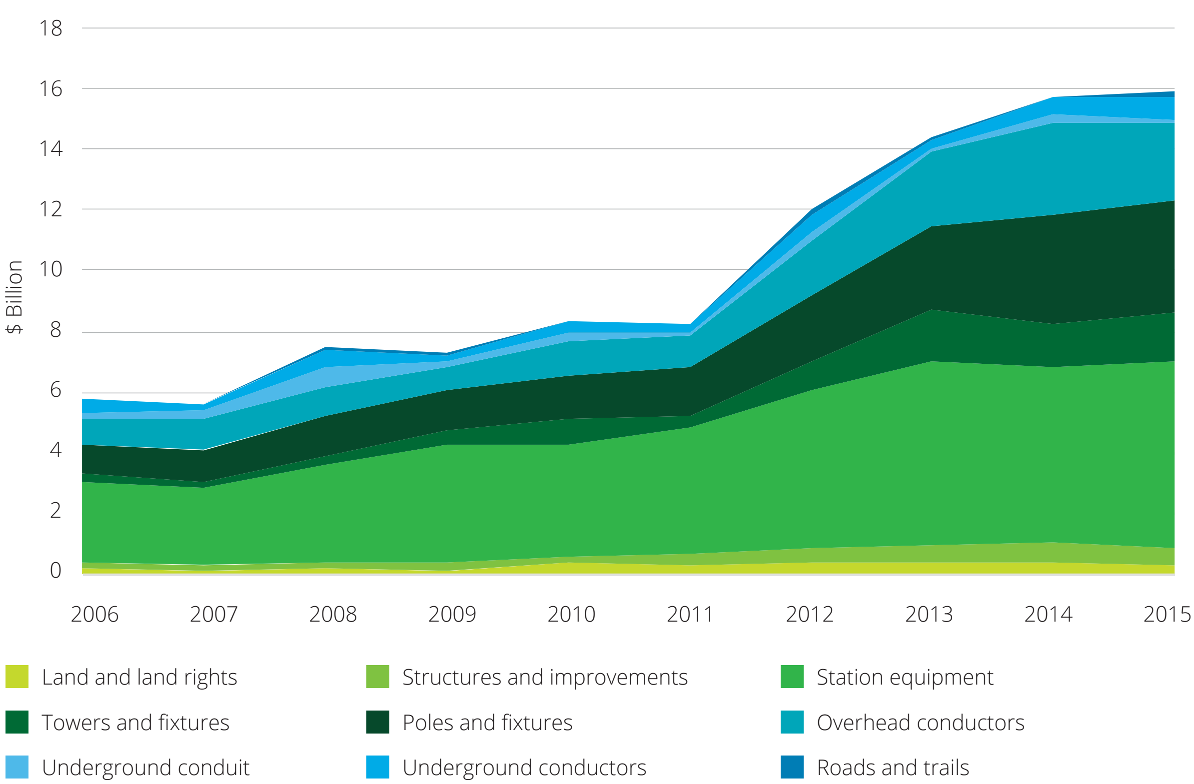


Source: RRA and SNL Energy, Deloitte analysis. RRA and SNL Energy are offerings of S&P Global Market Intelligence.

The T&D category of spending includes both physical upgrades of infrastructure, as well as the application of "smart" technology to make the electric grid more efficient, reliable, and responsive—and to pave the way for two-way power flows from an expanding array of distributed energy resources. The discussion below details drivers and recent expenditures in transmission, distribution, and grid modernization, all of which fall under T&D.

- **Transmission**
  Transmission expenditures reported to the Federal Energy Regulatory Commission (FERC) by investor-owned utilities, transmission companies, and generation/transmission companies nearly tripled in the last decade, increasing from $5.8 billion annually in 2006 to about $15.9 billion in 2015, as illustrated in Figure 3.[7] Towers, poles, fixtures, and overhead conductors were some of the largest and fastest growing categories of investment during the period, combined with a hefty chunk of spending on substations and related equipment. Investment is driven by the need to boost grid reliability, resiliency, and security; harden structures against severe weather or physical attack; replace aging infrastructure; reduce grid congestion; integrate renewable energy resources; adjust to regional shifts in electricity demand; and enable system flexibility to accommodate distributed resources. In addition, transmission system expenditures are rising in tandem with construction labor and raw materials costs.[8]

Figure 3. Major electric utility transmission spending by category (2006-2015)



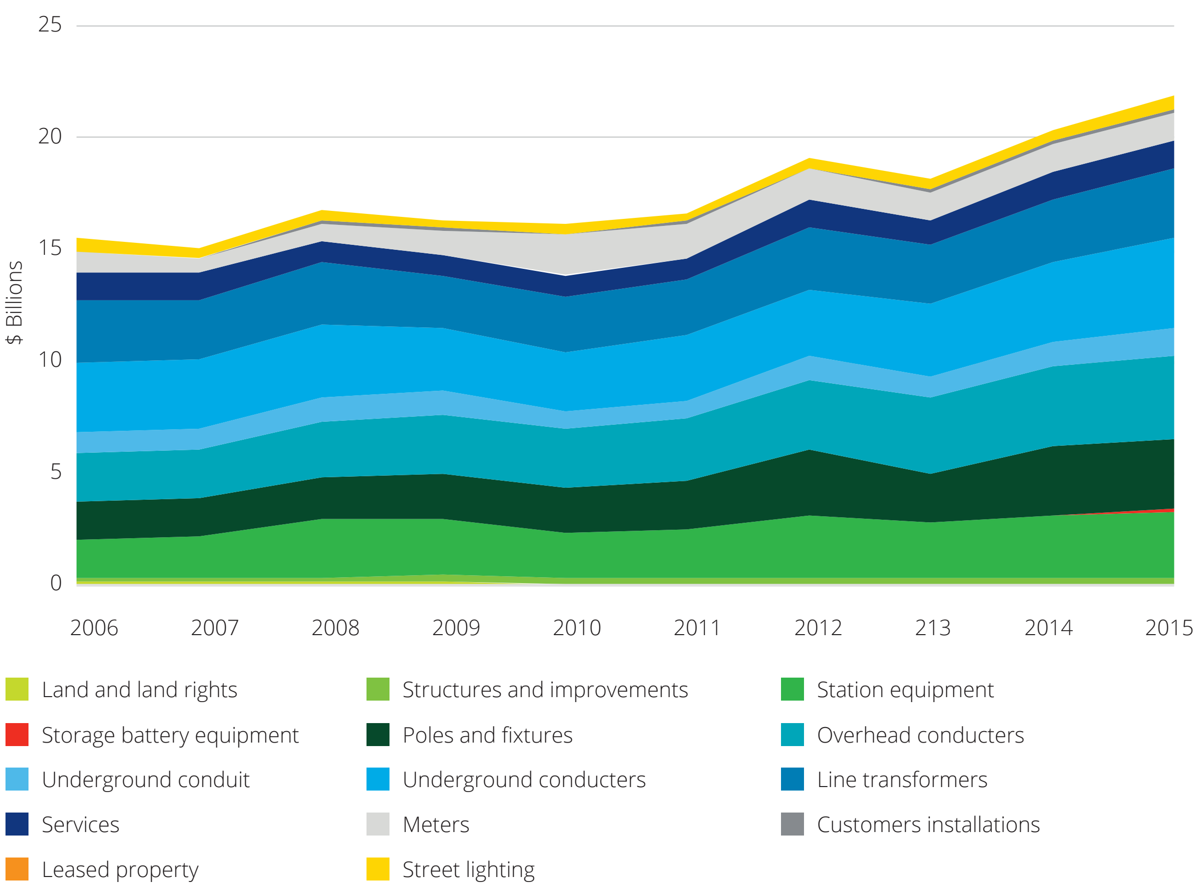
Note: The transmission and distribution expenditure data in Figures 3 and 4 are not directly comparable to T&D segment estimates in Figures 1 and 2 due to differences in the reporting universe, timeframe, and items included

Source: SNL Energy, FERC Form 1. SNL Energy is an offering of S&P Global Market Intelligence.

Also bolstering transmission system investments are the favorable incentive-based rate treatments that FERC implemented under the Energy Policy Act of 2005, providing utility and transmission companies with more attractive rates of return on equity and a smoother avenue to recover investments in the transmission infrastructure.[9] This provision was sparked by the electric power blackout of August 2003 that rolled from the Midwest to the Eastern US, lasting up to four days and causing several billion dollars in economic losses.[10]

- **Distribution**
  The system of substations, transformers, poles, and wires that reduces voltage and carries electricity to households, factories, schools, and businesses has attracted even more substantial levels of investment, and is increasingly the primary focus of electric companies. Distribution expenditures reported to FERC by investor-owned electric utilities, diversified utilities, and wholesale generation/transmission companies increased 42 percent over ten years, from $15.5 billion in 2006 to nearly $22 billion in 2015 (see Figure 4). Once again, the most popular and fastest growing categories of expenditures were poles and fixtures, overhead conductors and station equipment.

Figure 4. Major electric utility distribution spending by category* 2006-2015



Source: SNL from FERC Form 1.
*FERC Form 1 is a comprehensive financial and operating report submitted for electric rate regulation and financial audits, filed by "major electric utilities," defined as having: (1) one million megawatt hours or more; (2) 100 megawatt hours of annual sales for resale; (3) 500 megawatt hours of annual power exchange delivered; or (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses). http://www.ferc.gov/docs-filing/forms/form-1/data.asp

Much of this spending aims to harden the system against outages from calamitous weather events like hurricanes, blizzards, tornadoes, ice storms, and floods. Lawrence Berkeley National Laboratory and Stanford University researchers say you're not imagining it if you think the US electric grid has been impacted by increasingly severe weather events in recent years. Outages have lasted longer on average, and there's a distinct correlation with adverse weather events.[11]

The ability to recover quickly from outages is called "resiliency," and has become a key focus area for the electric power industry. Regulators are targeting the same goal, and several state public utility commissions have issued rulings designed to encourage strengthening the distribution infrastructure, where about 90 percent of outages occur.[12] There are many ways to boost resiliency—such as reinforcing and elevating substations in low-lying areas; upgrading and strengthening poles and lines; and burying lines when circumstances, and funding, permit. Adding transmission lines is another step utilities are taking to increase flexibility and resilience, as is deployment of smart grid technology, detailed further below.

- **Grid modernization**
  Utilities are investing in smart grid technologies to enhance resiliency, improve operating efficiency, and prepare for the growing influx of distributed energy resources (DER) on the grid, such as rooftop solar, battery storage, electric vehicles, microgrids, and demand response applications. These "grid modernization" initiatives will enhance flexibility and responsiveness, which are key to operating in the new world of two-way power flows, intermittent renewable power sources, and a growing array of new products and services.

  Deployment and integration of smart grid devices, components, and systems is advancing in three phases, reflected in the spending categories represented in Figure 5, and discussed further in Deloitte's "The power is on: How IoT technology is driving energy innovation."[13] They are:

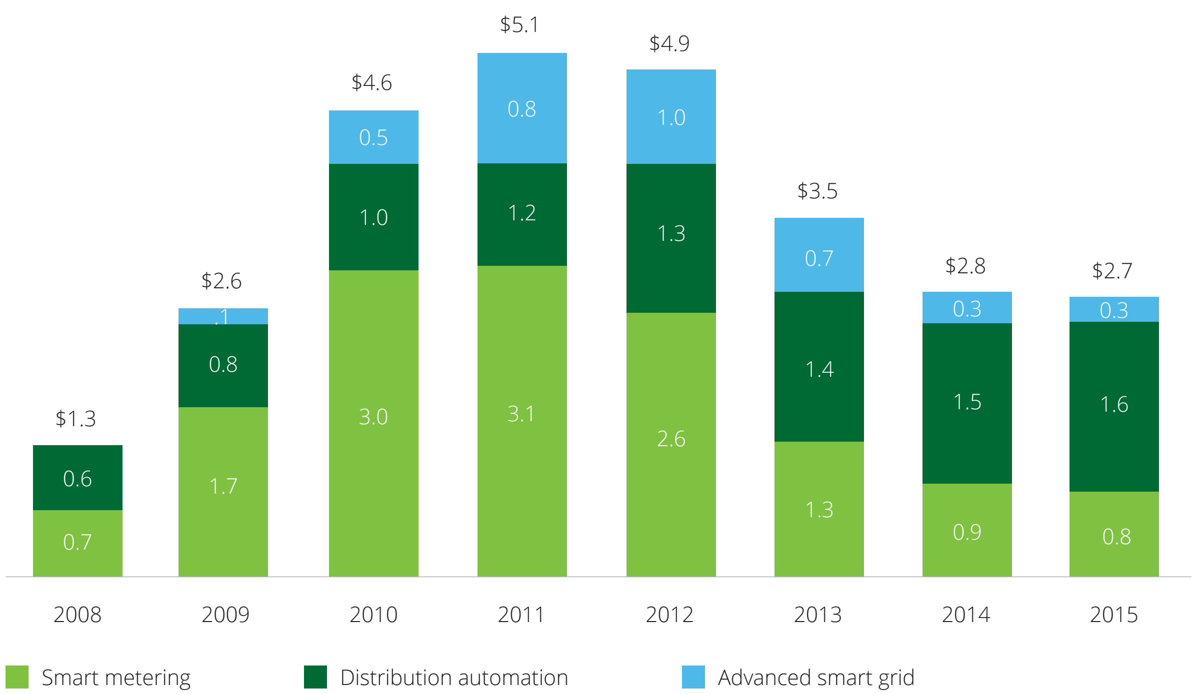
  – **Resilience** - Utilities are deploying smart meters and networked sensors and control devices to gather data, improve resilience, and monitor and control new distributed energy resources (DER). For example, smart meters at customer sites allow utilities to detect outages and expedite restoration of service. Smart inverters installed with rooftop solar systems can help utilities balance and integrate intermittent solar output with other grid resources.

  – **Enablement** - Utilities are using platforms, such as advanced distribution management systems (ADMS), to aggregate and analyze the data gathered through smart devices and actively manage and control resources. One goal is a "self-healing grid," which can automatically respond to system faults by rerouting power through automated feeder switches or dispatching DERs to reduce the number of customers affected by outages.

- **Optimization** – In this phase, utilities and other stakeholders will be able to use the data and insights generated in the enablement phase to make informed business decisions that optimize the use of DERs across the system. For example, utilities could use a feeder-level profitability assessment tool to evaluate which grid investments would be profitable and which are better left for the market to satisfy.

Grid modernization got a boost from $4 billion in Smart Grid Investment Grants (SGIG) under the American Recovery and Reinvestment Act of 2009 (the Stimulus Act) which, combined with industry spending, led to nearly $8 billion in related projects.[14] Nearly half of the funding went to advanced metering infrastructure, another $2 billion was invested in the distribution grid, and the rest in customer systems and transmission projects. More recently, the US Department of Energy

Figure 5. US smart grid spending by segment ($ billion)



Source: Business Council for Sustainable Energy (BSCE), Sustainable Energy in America Factbook, 2016, p. 131.
Data from Bloomberg New Energy Finance (BNEF) and Edison Electric Institute (EEI)

allocated $220 million in grid modernization funding through the Smart Grid Interoperability Panel (SGIP) to support research and development in advanced storage systems, clean energy integration, standards and test procedures, and other key areas.[15] At the same time, utility commissions in at least ten states have begun investigating the paths to grid modernization and some, like California, have ordered their state's utilities to prepare distribution grids for increased penetration of distributed resources.[16] New York, through its "Reforming the Energy Vision" regulatory program, is encouraging utilities to make DER integration a central focus.[17]

Despite these initiatives, much remains to be done. While nearly 65 million smart meters were installed nationwide by the end of 2015, it still represented less than 40 percent of US electricity customers.[18] According to an industry executive, the industry is "sorely behind the curve" in managing the enormous amounts of data required to optimize the modern distribution system.[19] About $17 to $24 billion per year would be needed to fully deploy smart grid technologies through 2030, according to the Electric Power Research Institute (EPRI), but benefits would far outweigh costs.[20] That amount far exceeds current spending (Figure 5), so it's clear that more funding and state initiatives combined with regulatory incentives or mandates would be required to drive such investment.

Generation spending poised to moderate after active period of fuel switching

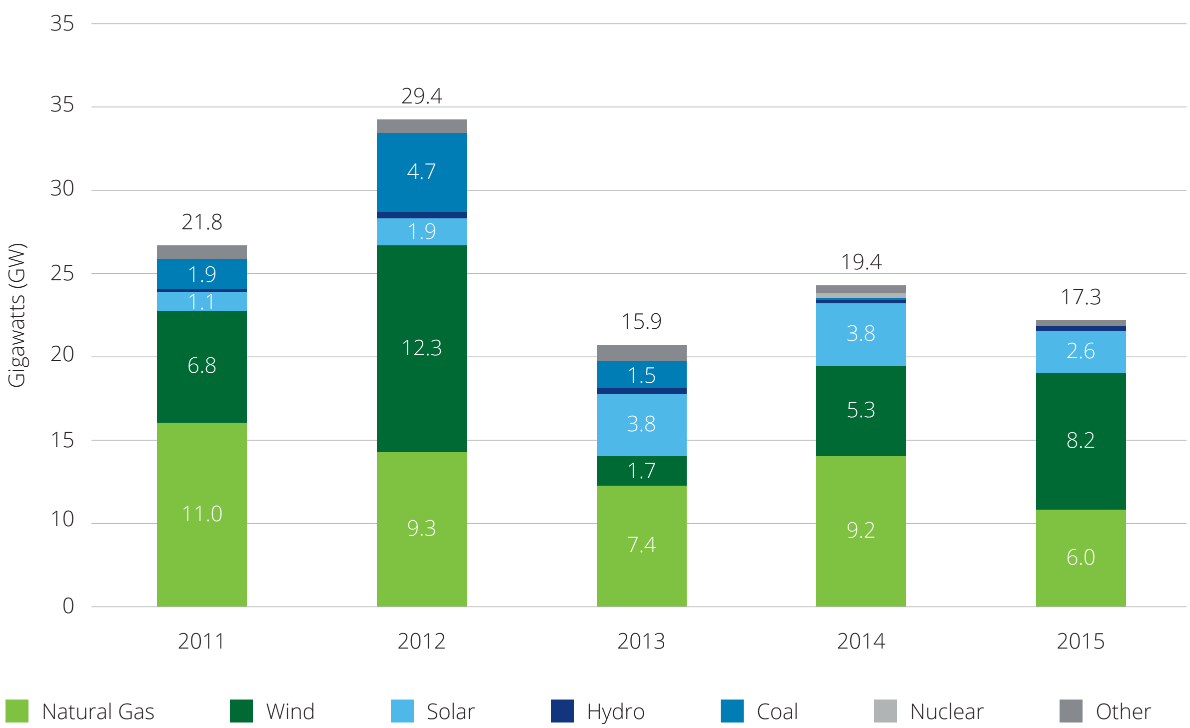
Generation was the second largest category of spending from 2008-2015. This category originally comprised new utility-scale generating capacity of all types, including renewables, as well as upgrades and retrofits to existing plants, often to comply with environmental mandates. However, by 2012, as environmental rulings and renewable requirements ramped up, many companies began reporting "environmental" and "renewable" spending separately. Other companies continued to group them together, so we'll start by taking a look at spending trends for all three combined.

The generation category by itself peaked at $32 billion in 2009, or about 48 percent of capital expenditures for the group (see Figures 1 and 2). In 2012, when you combine generation, environmental and renewable spending, the total spiked to $41.3 billion, and it's expected to climb nearly that high again in 2016, with current estimates totaling $39.7 billion.[21]

What's been driving generation spending? As previously noted, it's not due to rising consumption—although with US migration to Sun Belt cities in the South and West resuming after a recessionary lull, there may be some regional requirements for new generation.[22] On the whole, however, generation spending is being driven largely by fuel-switching from coal to natural gas and the movement toward a cleaner generation slate. In recent years, low-priced, abundant shale gas and multiple environmental mandates combined to render a large number of aging coal plants uneconomic and ripe for retirement. At the height of this trend in 2015, about 14 GW of coal generating capacity was retired, as the industry faced a market awash with cheap natural gas and a compliance deadline for the Environmental Protection Agency's (EPA) much-litigated Mercury and Air Toxics Standard (MATS).[23] This far exceeds the 4 GW of coal capacity retired in 2014, and the 7 GW slated to close in 2016. In fact, the total amount of coal capacity marked for retirement from 2016-2020 is more than 17 GW, plus about 12 GW of other generating capacity, primarily older, gas-fired plants.[24] Many other non-compliant coal plants have been retrofitted with emissions control equipment during the period, or converted to burn natural gas, biomass, or other fuels.

To replace this retiring capacity, the industry has overwhelmingly chosen natural gas and renewables. Much has been written about growing supplies of low-priced gas spiking a wave of natural gas-fired generation build, and the evidence of that is clear in Figure 6. The other big story, also illustrated in Figure 6, is new wind and solar capacity, which have been built not only to meet environmental mandates, but also to achieve state Renewable Portfolio Standards (RPS), take advantage of tax credits and declining technology costs, and diversify the generation portfolio. While companies are building new nuclear plants in some areas of the country, in other areas existing nuclear plants are being pressured by prices below the break-even point in competitive power capacity markets, largely due to low natural gas prices.[25] EIA calculates the levelized cost of energy (LCOE) for an advanced nuclear power plant entering service in 2022 at $95.2/MWh, while an advanced combined cycle natural gas plant would be $72.6/MWh.[26]

Figure 6. New generating capacity by fuel 2011-2015 (GW)



Source: Federal Energy Regulatory Commission (FERC), Office of Energy Projects, Energy Infrastructure Updates from December 2012-2015 http://www.ferc.gov/legal/staff-reports/2015/dec-infrastructure.pdf
Includes utility-scale plants with nameplate capacity of 1 MW or greater

For the past decade, in addition to building new plants, electric power companies have also acquired more renewable and natural gas generation assets than any other fuel types, as illustrated in Figure 7. After 2008, the number of gas and coal asset deals began to decline, while by 2011, wind and solar deals were gathering momentum. Some companies include these types of asset purchases in capital expenditure totals, while others do not. Electric companies also acquire electricity from wind and solar plants through power purchase agreements, which are not included in capital expenditures. Beyond generation, electric power companies acquired a number of other assets during the decade, most notably electric and natural gas transmission, distribution and production assets.[27]

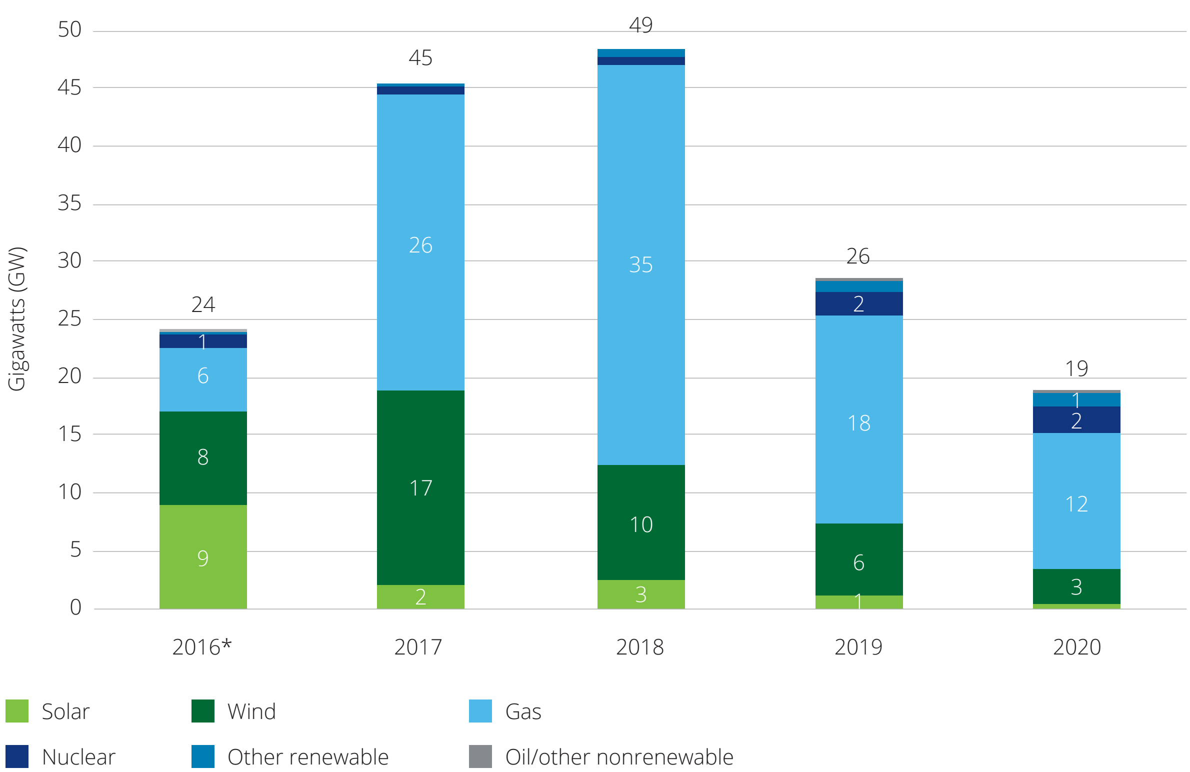
Figure 7. US electric company generation asset deals 2006-2015

(number of deals)									
	Wind	Solar	Gas	Coal	Biomass	Mixed fuel types	Water	Other*	Total
2006	16	1	32	6	9	10	3	6	83
2007	18	0	27	4	9	6	2	4	70
2008	16	1	25	6	9	4	6	3	70
2009	15	5	12	4	7	5	3	2	53
2010	11	9	11	2	7	3	4	3	50
2011	24	14	19	1	3	0	2	1	64
2012	22	12	14	2	3	3	3	1	60
2013	27	26	8	0	7	0	6	0	74
2014	24	29	11	2	2	5	1	3	77
2015	23	56	14	4	2	2	1	6	108
Total	196	153	173	31	58	38	31	29	709

Source: SNL Energy, includes all deals in the SNL database that involve electric power companies acquiring generation assets
*Other includes geothermal (12), nuclear (10) and oil (7). SNL Energy is an offering of S&P Global Market Intelligence.

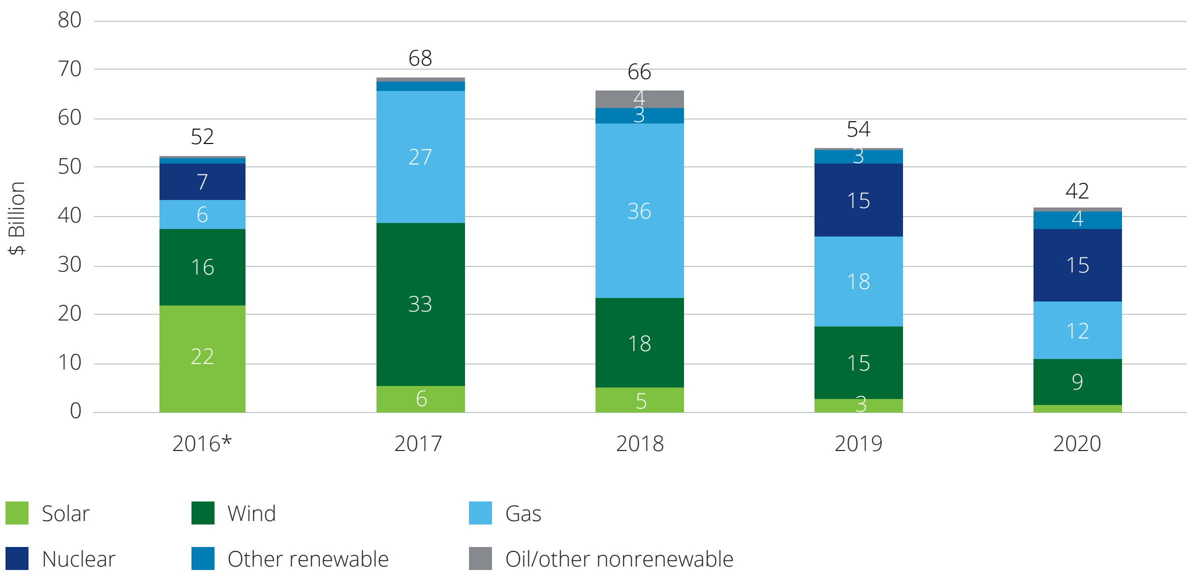
For the near term outlook, projections from the group of companies reflected in Figure 1 show generation spending peaking in 2016 at nearly $40 billion, including $4 billion for environmental compliance and about $7 billion for renewables, and tapering down to about $26 billion by 2018 for the three combined categories. Planned capacity additions for the 2016-2020 period for companies both within and outside the group of companies examined here is currently about 57 percent higher than actual capacity additions during the previous five years (2011-2015), at 163 GW compared to 104 GW.[28] But experience shows that planned capacity is not always completed. Figures 8 and 9 suggest the generation slate will continue to emphasize natural gas and renewable capacity. In fact, from 2016-2020, the announced project pipeline indicates companies plan to place in service about 95.5 GW ($98.9 billion) of natural-gas fired generation, more than double the 42.8 GW added in the previous five years. Another 44.1 GW of wind power ($90.9 billion) is indicated, compared with 34.3 GW added in the previous five years. And the data suggests 15.6 GW of solar power ($37.5 billion) will be added, compared to 13.2 GW from 2011-2015. Plans also include about 3.8 GW of other renewables ($12.6 billion) and 5.1 GW of other non-renewables ($1.2 billion). In addition, 5.6 GW ($36.9 billion) of nuclear capacity under construction is expected to begin service in 2019-2020.

Figure 8. Planned generating capacity 2016-2020 (GW)



Source: SNL Energy. SNL Energy is an offering of S&P Global Market Intelligence. Includes all projects SNL analysts have collected for companies within and outside the 47 company universe that are > 1 MW and will put at least 50% of their output on the grid. Projections from other industry sources may vary significantly, as some may include smaller plants or plants that have not been publicly announced yet. *2016 data includes only projects in advanced development and under construction, while 2017-2020 data also includes announced projects and projects in early development.

Figure 9. Planned generating capacity 2016-2020, project cost ($ Billion)



Note: These generating capacity costs do not compare directly with the company capital expenditure projections in Figures 1 and 2 because Figure 9 represents the total costs of plants entering service in a given year, and some of those costs may have been spent in a different year. In addition, these data cover a larger company universe and the timeframe and items included in the estimates may differ.

Source: SNL Energy. SNL Energy is an offering of S&P Global Market Intelligence.

These sums are fairly substantial, especially given the long-term sluggish outlook for US electricity demand growth. There are still some environmental mandates that will require hefty spending, as discussed below, and several states have either not yet reached or have increased their renewable portfolio standards (RPS). But with moderating demand growth, an increasing slate of alternatives to large centralized generation assets, growing uncertainty about the long term value of those assets, and additional scrutiny from regulators and consumers, some companies are considering alternatives to large scale centralized generation in their future generation portfolios.

There is a widening array of choices for utilities seeking to serve additional load or replace lost capacity without investing in centralized power plants, and several companies are exploring them. Faced with uncertainty around the long term return on investment from high ticket power plants in a world of flat demand growth and increasing supplies from customer-generated and other alternative sources, some are choosing to delay or defer new build. Instead, they are beefing up demand response and energy efficiency programs, deploying electricity storage and other distributed energy resources, or adding transmission to access resources from other regions. In the regulatory sphere, many state utility commissions require utilities to file Integrated Resource Plans for meeting forecast consumption and peak demand levels, and some specify a list of supply side and demand side resources utilities must consider.

The New York Public Service Commission (PSC) has taken it a step further. Under its "Reforming the Energy Vision" (REV) regulatory program, the NY PSC is requiring utilities to develop retail markets for solar, wind, fuel cells, battery storage, and other advanced energy services. REV's new rules still allow utilities to get paid under traditional cost-of-service regulation for building new infrastructure, but now they can also get earnings from "achieving alternatives that cut capital spending and provide a definitive consumer benefit via market-facing platform activities and transitional outcome-based performance measures."[29]

Initiatives like these may gradually change the pattern of utility investments. In the meantime, there are still some strong drivers for Environmental and Renewable spending over the next few years, as follows.

Environmental spending to drop slightly, but further regulation is expected

In the years leading up to 2015, electric power industry spending on compliance with environmental mandates rose as the industry prepared to meet the EPA's Mercury and Air Toxics Standard (MATS), a rule that aims to reduce power plant emissions of mercury, arsenic, and other metals under amendments to the 1990 Clean Air Act.[30] Although the courts remanded MATS to the EPA for revision in June 2015, the regulation is still being enforced and electric companies have invested billions to comply.[31] In another move to enforce the Clean Air Act, the EPA issued the Clean Power Plan (CPP) in 2015, with the goal to reduce power sector greenhouse gas emissions by 32 percent below 2005 levels by 2030.[32] The CPP was stayed by the Supreme Court in February 2016 and may be in litigation for some time, but it is nevertheless spurring additional plans and investment in the transition to a cleaner generation fleet, which much of the industry sees as "writing on the wall" regardless of the outcome of the case. Other environmental regulations that may require long-term capital investments include rules addressing coal combustion residuals, effluent limitation guidelines, and cooling water intake structures.[33]

Renewable spending projected to ease, though several drivers continue to support it

According to EEI, the electric power industry has built virtually all of the wind, geothermal, and hydropower generation capacity in the US today, as well as about 60 percent of the solar power capacity, and is spending about $9 billion per year on renewable energy.[34] The $9 billion figure may be higher than the capex breakdowns cited in this report because not all companies report renewables spending separately and the reporting universe differs. There are a number of drivers for sustained high investment in renewables.

A primary driver is RPS goals and mandates. Currently 37 states, four US territories, and the District of Columbia have RPS or voluntary goals that require a certain percentage of electricity sold by utilities be from renewable sources by a target date.[35] The target years

range from 2015 to 2045 and renewable percentage goals vary widely. Some of the most ambitious are California's mandate to reach 50 percent by 2030, Vermont's goal to reach 75 percent by 2032, and Hawaii's target of 100 percent by 2045.[36]

Other drivers of electric industry renewable investment include tax incentives, declining costs of wind and solar power, increasing customer demand for renewables, generation portfolio diversification, price transparency, and anticipation of additional environmental regulation, especially the Clean Power Plan (CPP). On the tax front, under the December 2015 omnibus spending bill, the federal 30 percent Investment Tax credit (ITC) for solar was extended for projects beginning construction before December 2019, gradually stepping down to 10 percent for those beginning after 2021. The wind Production Tax Credit (PTC) was extended through 2019, with annual phasedowns beginning in 2017.[37] In addition, the costs of building both utility-scale wind and solar power plants declined about 60 percent from 2010-2015.[38]

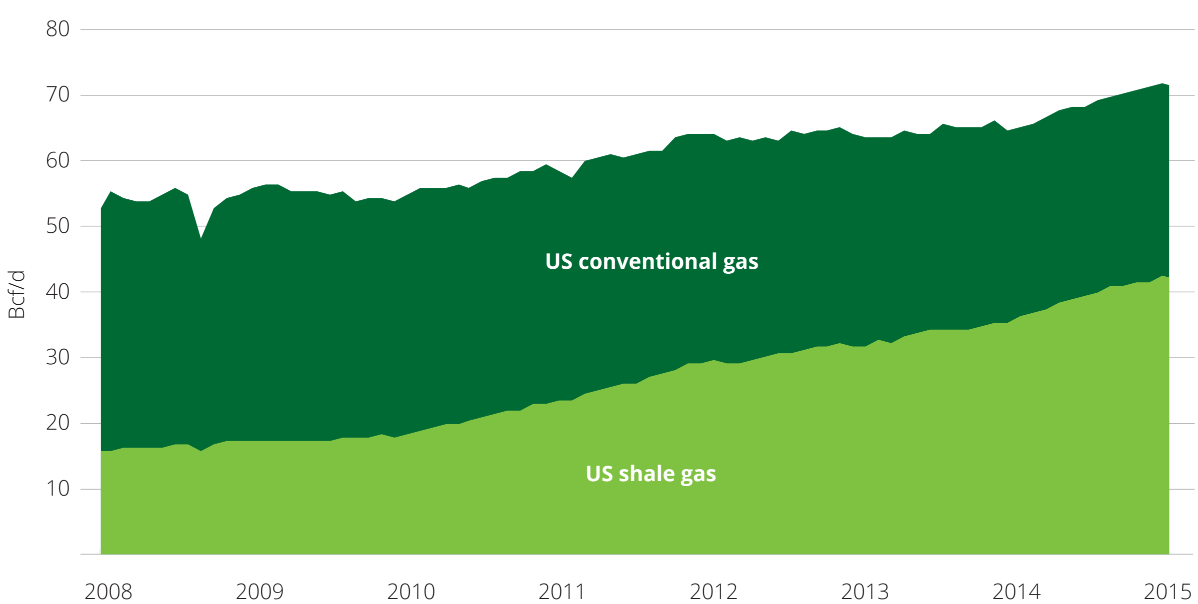
Further, electric utilities are responding to their customers' growing interest in electricity from renewable sources. In Deloitte's sixth annual nationwide study of energy customer perspectives, the *Deloitte Resources 2016 Study*, 56 percent of consumers surveyed rated the statement "Utilize clean energy sources to be better stewards of the environment for future generations" as one of the top three energy issues most important to them.[39] For electric companies, wind and solar power provide an increasingly attractive option to diversify their generation slates to avoid reliance on just one or two energy sources that may be susceptible to fuel price volatility or supply disruptions. In addition, companies that build renewable generation know they can often sell the power to other utilities at higher prices than fossil fuel-generated power, since many utilities have requirements to purchase electricity from renewable sources to meet state RPS.[40]

Finally, if the Clean Power Plan emerges from litigation and is implemented, the North American Electric Reliability Corporation (NERC) estimates it could spark an additional 10-20 GW of wind and solar capacity by 2030 on top of the 100-110 GW of renewable capacity additions already projected for the period.[41]

Natural gas infrastructure spending grows amidst opportunities across the value chain

Investment in natural gas pipelines, storage and distribution has been the fastest growing spending category for electric and gas companies, more than doubling from 2008-2015, and is expected to reach nearly $24 billion in 2016. As a share of total spending, it's projected to comprise an estimated 21-22 percent in 2016-2018, compared to 9 percent in 2008 for the group of companies tracked in this report.[42] Increased spending is driven by opportunities across the gas value chain. Electric companies are investing in abundant shale gas reserves, wells, and midstream infrastructure to take advantage of growth, lock in lower-priced fuel, and ensure local pipeline capacity will afford access to supplies for the burgeoning fleet of gas-fired power plants. Natural gas supplies are abundant, but regional gas pipeline capacity constraints in New England and New York have contributed to sharp electricity price hikes during peak demand periods in recent winters.[43] US natural gas production increased 36 percent from 2008-2015, as illustrated in Figure 10. During this period, US natural-gas-fired power generation rose by more than 30 percent, and exceeded coal-fired generation on a monthly basis for the first time in April 2015.[44] Coal and natural gas each provided about one third of all US electricity generation in 2015, and the EIA forecasts that natural gas-fired generation will surpass coal-fired generation on an annual basis for the first time in 2016.[45]

Figure 10. US natural gas production from 2008-2015



Source: EIA Short Term Energy Outlook, May 2016

At the same time, electric and gas companies are upgrading and expanding the country's aging gas distribution infrastructure to serve new facilities, address safety considerations, and comply with state and federal regulations. According to American Gas Association CEO Dave McCurdy, the gas industry is spending $22 billion annually to help enhance the safety of natural gas distribution and transmission systems.[46] Another driving factor is that these investments in natural gas transmission and distribution are a source of relatively stable, regulated returns for utility companies.

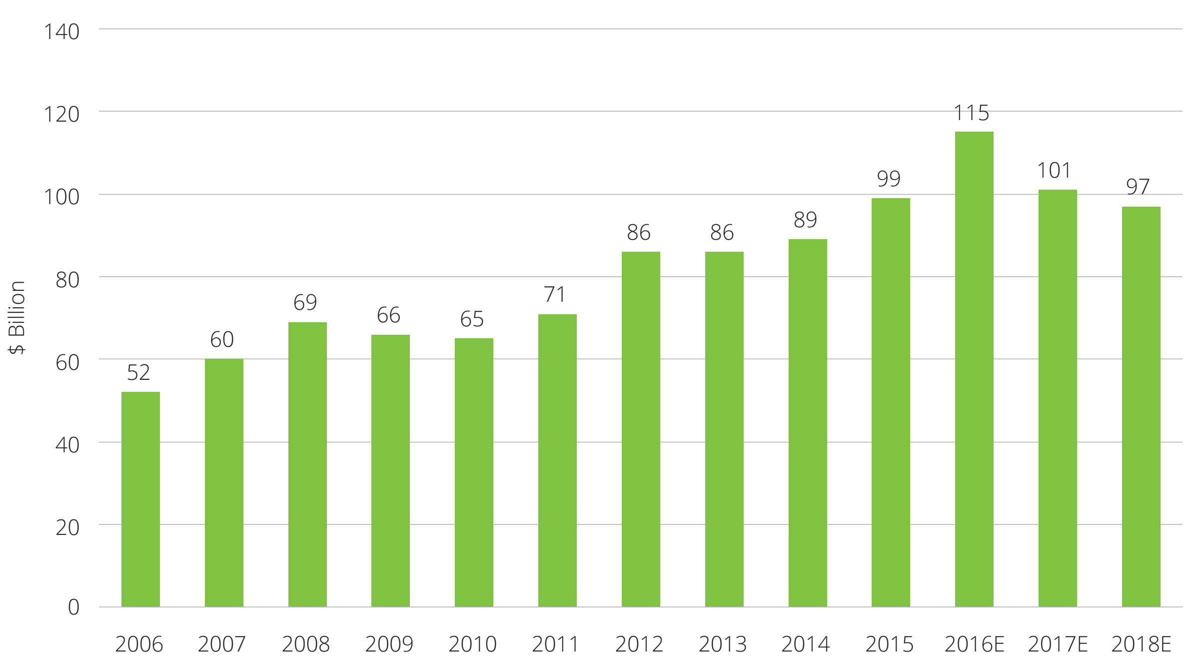
Further investment in the gas space is also reflected in the recent spate of electric power company mergers with gas utilities, such as the Southern Company/ AGL Resources, Duke Energy/Piedmont Natural Gas, and Dominion Resources/Questar Corporation deals. Transactions like these are driven by efforts to ensure gas supply, lock in lower gas prices, provide stable revenue opportunities as electric power demand growth moderates, and capitalize on the move to a cleaner power generation slate.

Are current spending levels sustainable?

Electric and gas industry capital expenditures for this group of companies nearly doubled over the decade from 2006-2015, rising from $52 billion to $99 billion. What's more, spending is estimated to reach an unprecedented $115 billion this year, and even though projections show it moderating slightly in 2017-2018, the amounts are still substantial. In addition, analysts note that current year forecasts are sometimes overestimated, while expenditures for two years out are often underestimated.[47] There are a number of drivers for continued high spending levels, as previously discussed, so it would not be surprising if 2017-2018 spending rose above the amounts in Figure 11.

How long can these spending levels continue? The answer depends partly on whether the costs are passed on to customers through rate increases. As Figure 12 shows, state utility commissions decided 953 cases involving the amount of revenue regulated electric and gas utilities are permitted to collect from ratepayers in

Figure 11. Total capital expenditures for 47 company universe, historical and forecast



Source: RRA and SNL Energy. SNL Energy is an offering of S&P Global Market Intelligence.

Figure 12. Electric and gas base rate changes 2006-2015*

Year	Electric base rate changes ($M)	Number of electric rate cases	Gas Base rate changes ($M)	Number of gas rate cases
2006	1,318.1	39	392.5	23
2007	1,405.7	43	645.4	43
2008	2,823.3	44	700.1	40
2009	4,191.6	58	483.9	36
2010	4,922.4	78	776.8	50
2011	2,595.2	57	367	31
2012	3,080.6	71	263.8	41
2013	3,326.5	63	495.1	39
2014	2,053.9	51	529	50
2015	1,887.0	56	487.6	40
Total	27,604.3	560	5,141.2	393

Source: RRA and SNL Energy. SNL Energy is an offering of S&P Global Market Intelligence. Includes data for the largest investor-owned/privately held electric and gas utilities in the US, excluding municipals, cooperatives, and government owned power authorities; tracks only cases in which the company has requested a rate change of at least $5 million or a rate change of at least $3 million was authorized.
* Base rate changes are the aggregated revenue requirements from regulatory rulings in general rate cases each year, excluding rate changes from adjustment clauses (which may include fuel and purchased power costs) or rider mechanisms.

the decade from 2006 to 2015, which resulted in close to $33 billion in additional revenue requirements over the ten year period, including almost $28 billion for electricity customers.

Electric and gas utilities began to file more rate cases in 2007, after a decade of low activity due in part to restructuring-related rate freezes and falling interest rates.[48] By 2007, most of the rate freezes had expired and companies began planning for the substantial new investment required to upgrade infrastructure and comply with environmental regulations in a period of uncertain demand growth. Rate case activity peaked in 2010, with 128 cases decided and $5.7 billion in base rate increases (Figure 12), and it has remained substantial since then.

But customers may not have felt the full impact of these rate increases so far, because just as electric utilities' capital spending programs were beginning to ramp up in 2008-2011, something else was happening: shale gas production was rising fast, and natural gas prices were falling sharply. In fact, the effect of electric utility rate increases on customer bills has been softened in many cases by declining gas prices, which utilities have passed through as fuel rate decreases, sometimes offsetting electric rate increases. Low natural gas prices were the key driver behind 27 to 37 percent reductions in on-peak wholesale electricity prices at major US trading hubs in 2015, and even steeper declines in 2016.[49] In fact, electricity prices have fallen so sharply that they are now about one third of a typical residential electric bill, down from about half eight years ago.[50]

However, despite lower wholesale gas and electricity prices, high capital expenditures and resulting rate increases have pushed overall electric bills up nearly 22 percent for residential customers over the last ten years, and about 12 percent for commercial and industrial customers (see Figure 13). Notably, after adjusting for inflation, the price changes amount to about a 4 percent increase for residential customers, and an effective decrease of nearly 6 percent for commercial and industrial customers, since rate increases in those segments have been outpaced by inflation.

Figure 13. US retail electricity price increases from 2006 to 2015

Average US retail price of electricity	2006 Cts/kwh	2015 Cts/kwh	10-year change %	Inflation-adjusted 2006 price in 2015* Cts/kwh	10-year change inflation-adjusted Cts/kwh	Inflation-adjusted 10-yr change %
Residential	10.4	12.67	21.8%	12.23	0.44	4.2%
Commercial	9.46	10.59	11.9%	11.12	-0.53	-5.6%
Industrial	6.16	6.89	11.9%	7.24	-0.35	-5.7%
Transportation	9.54	10.17	6.6%	11.22	-1.05	-11.0%
TOTAL all sectors	8.9	10.42	17.1%	10.46	-0.04	-0.4%

Source: EIA electricity data browser[51]
*Calculated using US Bureau of Labor Statistics inflation calculator at http://www.bls.gov/data/inflation_calculator.htm

So, while consumers are beginning to see the effects of high capital spending in their electric bills, the full price impact of the industry's expansive capital program may not have been felt so far. Critical upgrades to the electric and gas transmission and distribution systems, grid modernization, and the move to lower emission generation sources are being partially funded thanks to low natural gas prices. Capital spending programs have also been aided by sustained low interest rates, bonus depreciation rules, and the fact that tax rates for dividends have not increased. But any of these factors can and may change over time, which could have a dampening effect on capital expenditures.

Take natural gas prices. The average May 2016 Henry Hub spot natural gas price was $1.92 per MMBTU, down 85 percent from its June 2008 peak of $12.69 per MMBTU. Deloitte MarketPoint sees the price firming at about a 7 percent compound annual growth rate (CAGR) from 2016 to 2020, approaching $4.00 to $4.25 per MMBTU by 2020 (see Figure 14). If fuel costs rise, the increase will be passed through to electricity customers, and rising retail electricity bills could prompt regulators to consider all options at their disposal rather than only rate increases. Rising customer electricity bills can also make electric utilities more vulnerable to competition, like rooftop solar and electricity storage providers.

Figure 14. US Spot Natural Gas Prices at Henry Hub

Source: EIA and *Deloitte MarketPoint Spring 2016 Reference Case

In addition, interest rates are still relatively low historically (see Figure 15), but they may rise over time. This could act as a drag on investment as debt-financing becomes more costly.

Figure 15. Interest rate on 10-year T-note

Source: Board of Governors of the Federal Reserve System, FRED, 10-Year Treasury Constant Maturity Rate
https://research.stlouisfed.org/fred2/graph/?s%5B1%5D%5Bid%5D=DGS10

Another factor that could change and adversely impact the capital investment outlook is tax reform. For example, bonus depreciation, which allows taxpayers including investor-owned utilities (IOUs) to further accelerate depreciation deductions for properties they acquire or build such as generation, transmission, and distribution assets, was extended in December 2015 through 2019.[52] By allowing faster depreciation of assets, bonus depreciation reduces taxable income and can increase cash flow, which may help fund additional investment. However, as bonus depreciation phases down from 50 percent to 30 percent in the coming years, it could slow investment. At the same time, the policy is a double-edged sword for regulated utilities because it does not always increase cash flow. Faster depreciation and the resulting lower taxes may reduce a utility's rate base, which could decrease revenue requirements. The availability of bonus depreciation since 2008 has resulted in some IOUs experiencing net operating losses (NOLs) and being unable to immediately realize these tax benefits.

In addition, the utility industry has lobbied consistently against an increase in dividend tax rates, but if a future tax reform plan ever succeeds at targeting dividends, it could reduce investor interest in the traditionally high dividend utility sector, potentially increasing cost of capital and dampening utility expenditures. Other proposals related to comprehensive tax reform would reduce the corporate income tax rate and repeal

accelerated tax depreciation. Such a combination of tax changes would also affect availability of cash as well as rate base and could impact capital investments.

In sum, the sustained trend of historically high capital expenditures in the electric and gas industry depends on a variety of economic and political factors, which will likely change over time.

Conclusion

The last decade's doubling of capital expenditures has helped accomplish some critical upgrades to the US electric and natural gas infrastructure. It is already beginning to make the electric grid more reliable, resilient, flexible, and clean. Similarly, gas infrastructure investment is enhancing pipeline safety, bringing new shale supplies to market and sharply reducing natural gas and electricity commodity prices for customers. In several areas of investment, like grid modernization and upgrading the gas distribution system, there is still a long way to go and substantial additional investment will be needed over many years. But most of these investments will bring future benefits by enabling the flexible grid of the future, and helping to avoid costly and potentially tragic disasters such as long-term, large-scale electricity outages or gas system explosions.

So far, these investments have been partially offset by lower fuel costs enabled by the shale revolution and the general downturn in oil and gas prices. Most utility customers have not seen sharp increases in their bills, but that could change. Factors such as rising natural gas prices could increase customer bills and make state utility commissions less amenable to rate hikes to cover capital investment programs.

For electric utilities, it will be important to plan for multiple scenarios and prioritize investments to ensure they're investing in assets with long term growth potential. This can be challenging in a transforming industry, where new technologies, products, and competitors emerge regularly. In this environment, large capital outlays for centralized generation assets may become less common as regulatory systems evolve and electric companies consider all of the alternatives.

In the future, both electric and gas utilities will continue to invest in a safer, more reliable, and environmentally responsible energy infrastructure, but they might have to renew their focus on efforts to keep energy supplies affordable.

Appendix: Exploring company investment patterns

A closer look at individual company expenditure profiles and financial metrics helps uncover common characteristics among companies with similar capital allocation patterns or companies with the highest levels of total capital expenditures.

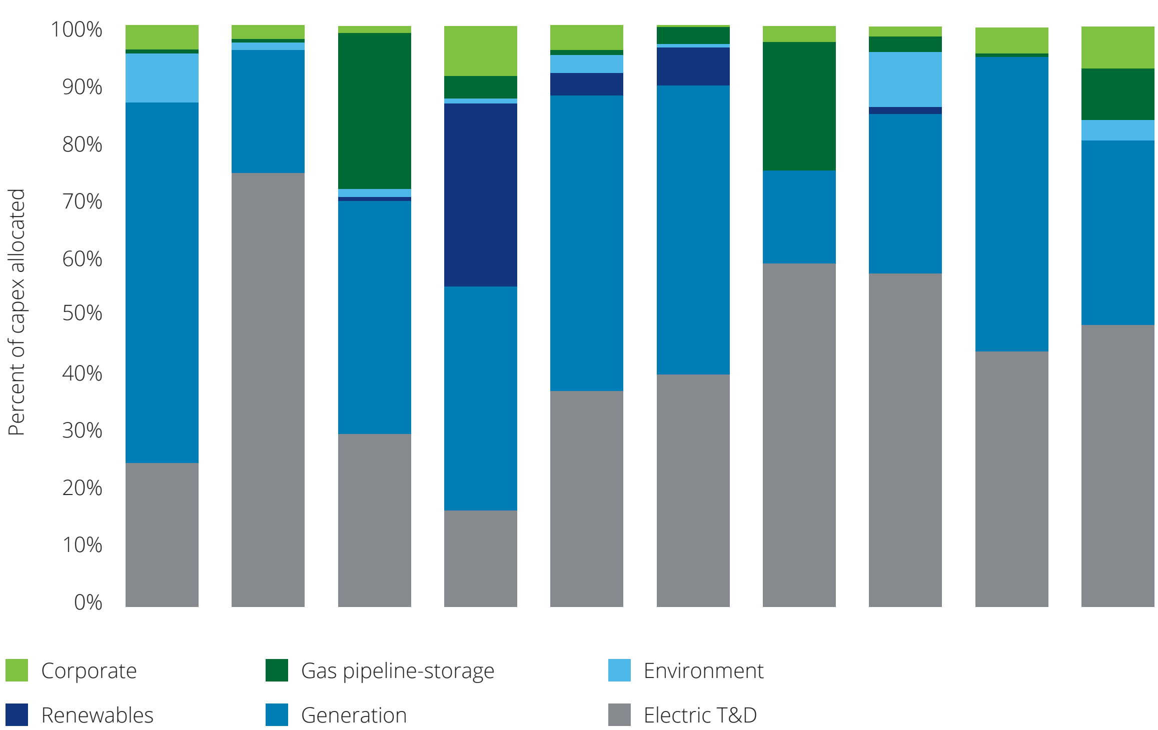
Capital allocation patterns among the top ten investors (2008-2015)

First, let's take a look at the companies with the highest levels of investment in the 2008-2015 period, as they account for nearly half of all expenditures. In Figure 16, the top ten are ranked according to total amount of capital spent, moving from highest on the left to lowest on the right.

What types of companies had the highest capital expenditures out of the 47 companies profiled in this report and how do they compare with the rest of the group?

- The top ten investors were some of the largest companies in the group, with 2015 revenue averaging $16.8 billion per company, compared with $7.8 billion for the whole group
- In the seven years from 2008-2015, these ten companies invested over $303 billion, nearly half of the total $631 billion spent by the whole group.
- **Type of company** – Six of the top ten companies have merchant unregulated alongside their regulated operations. The other four have only regulated operations.

Figure 16. Capital expenditure estimates by company and category for top 10 investors (2008-2015)



Note: Each bar represents one company, and the colors within the bars signify the estimated percentage of the company's expenditures that was allocated to the corresponding category during the period.

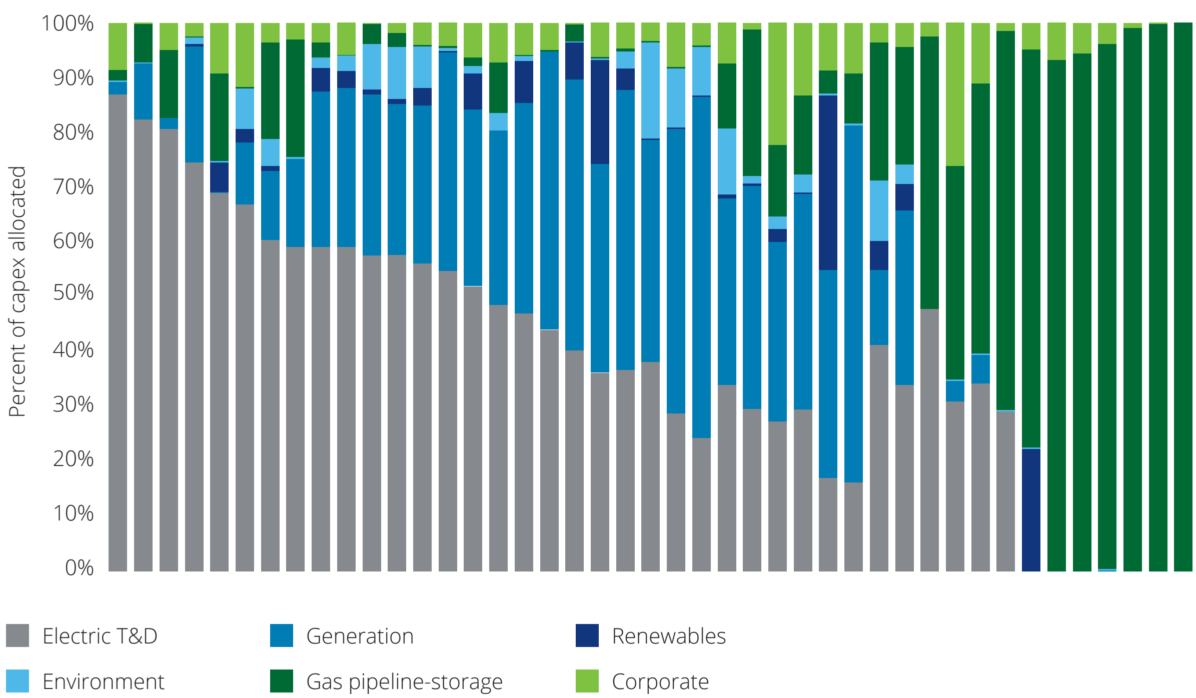
Source: RRA and SNL Energy and Deloitte analysis. SNL Energy is an offering of S&P Global Market Intelligence. See methodology described on page 2. Total amounts spent variedsignificantly – this image represents the percentages of total spend for each reporting company.

- **Region** – The top ten investors shown in Figure 16 are primarily located in Southern states (half), while two are located in the West, two in the Midwest, and one in the Northeast (according to US census regions).
- **Return on invested capital (ROIC)** – The companies had an average annual ROIC over the period of 4.9 percent, slightly higher than the average ROIC of 4.6 percent for the whole group. Individual companies' ROIC ranged from 3.4 to 7.4 percent.
- **Total shareholder return (TSR)** – TSR for the group over the seven year period averaged 54 percent, which was significantly less than the larger group average of 98 percent and the midpoint of 99 percent. Among the top ten investors, TSR varied greatly—from -51 to 127 percent. Three in ten of the companies had a TSR above 100 percent, while three others had negative TSR. The midpoint was 75 percent.
- **Revenue growth** – Average CAGR for revenue for this group over the seven year period was 1.87 percent, although it ranged widely, from -2.9 to 8.6 percent across individual companies. Average CAGR for the larger group was zero percent.
- **Bond ratings** – Five of the top 10 companies shown in Figure 16 companies currently have S&P bond ratings of A- , two have BBB+ ratings and three are rated BBB. Ratings of A- to BBB+ were typical of the larger group as well.

Capital allocation patterns across the entire company sample

Moving on to the whole group of 47 companies analyzed in this report (Figure 17), we'll explore the historical and projected patterns of spending across companies and identify common characteristics among groups of companies with similar spending patterns.

Figure 17. Capital expenditure estimates by company and category (2008-2015)



Note: Each bar represents one company. There are 43 bars rather than 47 because four companies did not segment expenditures.

Source: RRA and SNL Energy, Deloitte analysis. SNL Energy is an offering of S&P Global Market Intelligence.See methodology description on page 2. This image represents the percentages of total spend for each reporting company. Total amounts spent varied significantly.

From the data illustrated in Figure 17, we can identify at least three different capital allocation patterns among the 43 companies that disclosed segmented expenditures, differentiated by the percentage of the companies' total capital expenditures directed into various categories of investment over the period. Below are some of the characteristics of companies within groups that allocated capital primarily to electric transmission and distribution; generation; and natural gas infrastructure (see also Figure 18).

Group 1 – Top T&D investors – This group is comprised of all companies that allocated > 60% of 2008-2015 capex to electric transmission and distribution.

- Seven of the 43 companies that segment capital expenditures allocated more than 60 percent of their total capital expenditures to T&D.
- **Company type** – They were regulated companies, including five regulated wires companies and two wires companies that also own merchant generation.
- **Region** – On a regional basis, these companies were fairly evenly spread across the country, with two from the South, two from the West, two from the Northeast, and one from the Midwest.
- **ROIC** – Average annual ROIC for the seven companies was 4.4 percent, with a range of 2.2 to 6.1 percent; this compares with average ROIC of 4.6 percent for the whole group.
- **TSR** – Average TSR for these companies over the 2008-2015 period was 89 percent, with a range of 23 to 160 percent. This compares with 98 percent for the whole group.
- **Revenue growth** – The CAGR for revenue for the period was -1.2 percent for the group, although individual companies ranged widely—from -8.4 to 8.6 percent. CAGR for the larger group was zero percent.
- **Bond ratings** – One out of the seven companies has an S&P bond rating of BBB, while three have ratings of BBB+.

Group 2 – Top generation investors – This group is comprised of all companies that allocated > 50% of 2008-2015 capex to the generation, renewable, and environmental categories combined

- Nine of the 43 companies that segment capital expenditures allocated 51-71 percent of their total capital expenditures to the combined generation, renewable, and environmental categories over the period. (As noted earlier, it is difficult to separate these categories reliably, since some companies do not distinguish between them).
- **Company type** - All but one company have both merchant unregulated and regulated operations; the other has only regulated.
- **Region** – Five out of nine were from the South, three from the Midwest and one from the West.
- **ROIC** – Average ROIC for the group over the period was 4.7 percent, ranging from 3 to 5.3 percent among the companies, compared with an average 4.6 percent for the whole group.
- **TSR** – TSR for the group averaged 64 percent; it varied widely across the companies, from -51 to 145 percent (compared with 98 percent for the whole group).
- **Revenue growth** – Revenue CAGR for the period averaged 2.6 percent for these companies, and ranged from 2.7 to 8.6 percent; significantly higher than the zero percent average revenue CAGR for the larger group.
- **Bond ratings** – Three had A- bond ratings, three had BBB+ and three had BBB ratings from S&P, similar to the larger group's ratings.

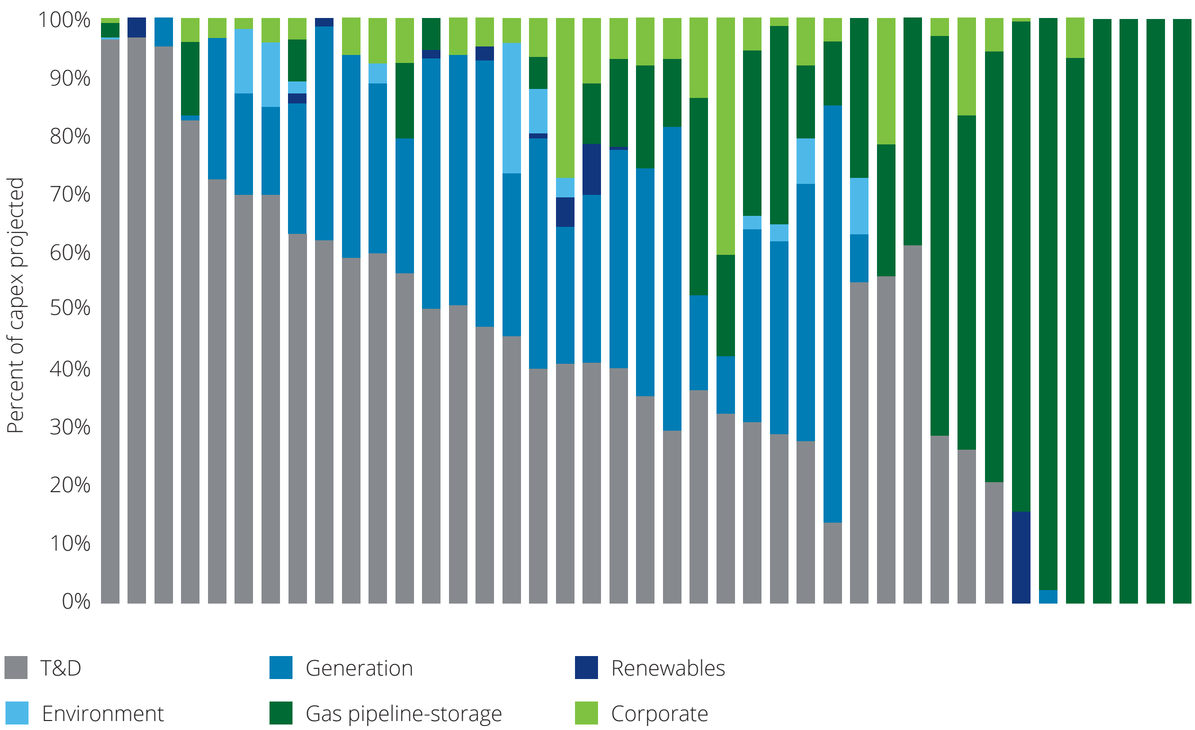
Group 3 – Top gas infrastructure investors – This group is comprised of all companies that allocated > 60% of 2008-2015 capex to natural gas pipelines, storage, and distribution.

- Eight of the 43 companies that segment capital expenditures allocated more than 60 percent of their capital expenditures to natural gas pipelines, storage, and distribution over the period; six of these companies focused more than 90 percent of expenditures on this category.
- **Company type** – This group is primarily comprised of regulated natural gas LDCs, some of which are currently merging with larger electric and gas companies.
- **Region** – Five out of eight of the companies are located in the South, two in the West and one in the Midwest.
- **ROIC** – The companies' average ROIC over the period was 5.2 percent, with individual companies averaging from 2.5 to 9.3 percent. This is higher than the 4.6 percent average ROIC for the larger group
- **TSR** – TSR for the group averaged 169 percent for the period, with a range of 39 to 278 percent for individual companies. This is significantly higher than the 98 percent for the whole group.
- **Revenue growth** – The CAGR for revenue over the seven year period for this group averaged 2 percent, with a range of -8 to 5 percent, higher than the zero percent average for the larger group.
- **Bond ratings** – This group of companies had higher bond ratings than the others – one company has an A+, two are rated A, two A- and three have BBB+ ratings from S&P.

Figure 18. Common company capital allocation profiles

	Top T&D spenders	Top generation spenders	Top gas spenders
Company type	Mostly regulated wires companies	Mostly integrated utilities with unregulated merchant generation and regulated utilities	Mostly regulated gas LDCs
Description	Companies that invested > 60% of 2008-2015 capex in electric transmission and distribution	Companies that invested > 50% of 2008-2015 capex in the generation, renewable, and environmental categories combined	Companies that invested > 60% of 2008-2015 capex in natural gas pipelines, storage and distribution
Number of companies	7	9	8
Region	Evenly spread across regions	Five out of nine companies are in the South	Five out of eight companies are in the South
ROIC	4.4%	4.7%	5.2%
TSR	89%	64%	169%
Revenue growth	1.2%	2.6%	2%
S&P bond rating	A (1), A-(2), BBB+ (3), BBB (1)	A- (3), BBB+ (3), BBB(3)	A+ (1), A (2), A- (2), BBB+ (3)

Figure 19. Projected capital expenditures by company and category (2016-2019)



Source: RRA and SNL Energy, Deloitte analysis. SNL Energy is an offering of S&P Global Market Intelligence. See methodology described on page 2. Total amounts spent variedsignificantly – this image represents the percentages of total spend for each reporting company.

Over the next 3-4 years, individual company projections reveal an increased emphasis on natural gas investment as a proportion of individual company spending compared with the 2008-2015 period. This is also borne out in the projections for overall spending by segment in Figure 2, where the proportion of spending for all companies in the natural gas category rises from 15 percent in 2015 to 25 percent in 2016, and remains above 20 percent in the following years. These company projections also show a reduced emphasis on generation when compared with the recent patterns of company spending in Figure 17, a factor also seen in the aggregate spending projections in Figure 2.

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Let's talk

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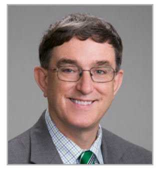

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THE COST OF CAPITAL TO A PUBLIC UTILITY

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East Lansing, Michigan

Table 3. ***Regression of Average Growth Rate on Dividend Yield and Risk Variables, 1958–1968***

	$GRAV = \alpha_0 + \alpha_1\,DIYD + \alpha_2\,LEVM + \alpha_3\,PEE + \alpha_4\,QLE$					
Year	α_0	α_1	α_2	α_3	α_4	*Cor. Coef.*
1958	.1376	−2.364	.0015	.0057	−.0085	.868
		−10.07	.24	.64	−1.01	
1959	.1536	−2.093	.0021	−.0167	−.0170	.881
		−10.89	.36	−2.19	−2.56	
1960	.1337	−1.844	−.0053	−.0088	−.0188	.898
		−10.22	−.10	−1.36	−2.87	
1961	.1210	−1.755	−.0105	−.0095	−.0113	.848
		−7.84	−1.48	−1.49	−1.52	
1962	.1372	−2.234	−.0007	−.0102	−.0161	.854
		−9.06	−.10	−1.58	−2.18	
1963	.1281	−2.269	.0016	.0002	−.0076	.871
		−9.67	.23	.04	−1.10	
1964	.1427	−2.258	−.0099	−.0125	−.0173	.862
		−8.76	−1.28	−2.04	−2.17	
1965	.1289	−1.818	−.0041	−.0098	−.0065	.857
		−8.10	−.66	−1.74	−.80	
1966	.1309	−1.415	−.0044	−.0142	.0028	.911
		−10.34	−1.01	−3.06	.46	
1967	.1164	−1.020	−.0088	−.0079	−.0093	.857
		−8.12	−1.97	−1.51	−1.34	
1968	.1324	−1.552	−.0061	−.0068	−.0015	.801
		−7.44	−.98	−.92	−.18	

NOTE: Numbers below regression coefficients are their *t* values.

While GRAVC is superior to GRAV, we cannot be certain that GRAVC is, in fact, completely free of error. Assume that the true value of expected growth is GTRU and that the relation between GRAV(*J,T*) and GTRU(*J,T*) is

$$GRAV(J,T) = \lambda_0 + \lambda_1\,GTRU(J,T) + ERR(J,T), \tag{5.6.6}$$

with $\lambda_0 \neq 0$ or $\lambda_1 \neq 1$. GRAVC eliminates the error in GRAV due to ERR, but it does not correct for systematic bias in GRAV. GRAVC will have systematic error if investors believe that, across all firms, GRAV is on average above or below the growth they expect to prevail in the future. While this is possible, there appears little ground for believing it to be true for utility companies.

If GRAVC is the rate of growth investors expect, the yield they require on a share is

$$KGAVC = DIYD + GRAVC. \tag{5.6.7}$$

Table 4 presents the sample means and standard deviations of GRAVC for 1958–1968 and, for comparison, the interest rate on Aa rated bonds.[7] KGAVC follows the broad movement in AAR over the eleven-year period, but from one year to the next they do not always move together. The spread between KGAVC and AAR appears large, but it is not beyond the bounds of reason.

Table 4. ***Sample Means and Standard Deviations of Share Yield Based on Predicted Growth Rate, GRAVC, 1958–1968***

	Share yield		
Year	*Mean*	*Std. dev.*	*Yield on Aa bonds*
1958	.0910	.0097	.0422
1959	.0966	.0081	.0471
1960	.0909	.0070	.0449
1961	.0835	.0056	.0450
1962	.0885	.0068	.0431
1963	.0885	.0068	.0439
1964	.0889	.0067	.0446
1965	.0912	.0049	.0475
1966	.0993	.0041	.0546
1967	.1028	.0023	.0640
1968	.0976	.0045	.0675

5.7 *Finite Horizon Growth Models*

A number of writers have questioned the validity of share value models based on the assumption that the current rate of growth

[7] Share yield based on GRAV instead of GRAVC has the same sample mean in each year, but the standard deviation averages about one-third larger.

in the dividend is expected to prevail forever.[8] If the dividend is expected to grow for N periods at the rate GRAV and thereafter at a long-run normal rate of GRLR, and if investors require a yield of KGON on the share, its price is given by the expression

$$\mathrm{PPS}(T) = \sum_{t=1}^{N} \frac{\mathrm{DIV}(T)\,[1+\mathrm{GRAV}]^t}{[1+\mathrm{KGON}]^t} + \frac{\mathrm{DIV}(T)\,[1+\mathrm{GRAV}]^N[1+\mathrm{GRLR}]}{[\mathrm{KGON}-\mathrm{GRLR}]\,[1+\mathrm{KGON}]^N}. \tag{5.7.1}$$

Given KGON, N, and GRLR in addition to DIV and GRAV, Eq. (5.7.1) can be used to arrive at the price at which a share should sell. However, we know PPS and want to establish KGON. This may be done if GRLR and N are known. The solution of Eq. (5.7.1) for KGON also will produce a measure of growth that is a weighted average of GRAV and GRLR, its value depending on their relative magnitudes and the value of N. The growth rate equivalent to GRAV for N periods and GRLR thereafter is

$$\mathrm{GRON} = \mathrm{KGON} - \mathrm{DIV}\,[1+\mathrm{GRAV}]/\mathrm{PPS} \tag{5.7.2}$$

An investigator who has reason to believe that a firm's dividend is expected to grow at the rate GRAV for N periods and at the rate GRLR thereafter reasonably might use this information to arrive at KGON and consider this measure of share yield superior to KGAV or even KGAVC. One advantage of KGON over KGAV is that the former does not require the regression analysis of sample data to arrive at the share yield for a firm. A more important advantage is that it is free of the systematic as well as the random errors of measurement in GRAV discussed in the previous section.

The problem involved in using Eq. (5.7.1) to arrive at an error-free measure of share yield is in arriving at the values of N and GRLR. Without special information N and GRLR must be assigned the same values for all corporations. However, doing so would not eliminate the random error, and it would not eliminate the systematic error unless the values assigned to N and GRLR were the correct ones for all firms in the sample. These are very brave assumptions.

Conceivably, we could test a set of values for N and GRLR as follows. Compute KGON and GRON for each firm. Regress DIYD on GRON and the risk variables. If the multiple correlation is higher with GRON than with GRAV as the growth variable, it is a better measure of growth. All possible combinations of N and GRLR could not be tested. Instead, GRLR = .045 was used on the assumption that this value could not be far off the mark, and GRON was tested for various values of N in the interval five to thirty years. The hypothesis was that if the multiple correlation reached a maximum for a value in the interval $5 \leq N \leq 30$, that value of N is the horizon and that value of GRON is the best estimate of the growth investors expect. What we found was that as N goes from five to infinity (GRON = GRAV when $N = \infty$) the multiple correlation fell, reaching a minimum at about $N = 15$, and then rose continuously. There is undoubtedly some technical explanation for these results, but regardless of the explanation the assumption of a common finite horizon for all shares cannot be used to obtain a better measure of growth than GRAV. Compared with KGAV, KGON eliminates neither the random nor the systematic error under the estimating methods available to us.

[8] For example, see B. G. Malkiel [29] and R. M. Soldofsky and J. T. Murphy [42].

5.8 *The Earnings Yield*

The earnings yield on a share has been widely used as a measure of share yield both in regulatory proceedings and in empirical research on security valuation.[9] Therefore, an examination of alternative measures of share yield is not complete without considering this alternative.

There are two conditions under which the earnings yield on a share is an accurate measure of the yield at which the share is selling. The derivation of Eq. (2.2.1) established that the earnings yield is correct when a firm pays all of its earnings in dividends, engages in no outside financing, and when, as a consequence, its dividends are not expected to grow. Without even looking at the

[9] On the latter see, for example, J. F. Weston [48] and Miller and Modigliani [32]. H. Benishay [3], D. H. Bower and R. S. Bower [4], and B. G. Malkiel and J. G. Cragg [30] used the price/earnings ratio in their empirical work.

What's Growth Got to Do With It? *Equity Returns and Economic Growth*

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Economic growth is generally considered to be an important driver of equity market performance because higher economic growth should lead to higher corporate earnings growth and this in turn should translate into higher stock market returns at least in the long run. As long as corporate profit margins, expressed as earnings divided by GDP, are stationary, this relationship should hold, and there is empirical evidence that, at least for the United States, profit margins are stationary (Cornell [2010]). But it is unclear whether this assumption also holds for small open economies like Switzerland, South Korea, or Taiwan, which are largely dependent on global exports. It is well possible that the cross-country correlation between equity market returns and gross domestic product (GDP) growth is low if globalization leads to shifts in competitive positions and global market shares for products and services that are reflected in the performance of local equity markets.

Ritter [2005, 2012] shows that cross-country correlations between real equity market returns and real GDP per capita growth is low, or even negative, for both developed and emerging markets. This effect may have many explanations. Estrada [2012] mentions the international diversification of global large-cap firms that dominate the performance of local market indexes. These global mega-caps have significant exposure to fast-growing international markets and thus may be more exposed to the global growth environment than the growth environment of their home market. This is especially true for smaller open economies that depend heavily on international exports of their products and services. The performance of the stocks of companies like Nestle or Samsung arguably depends only to a small extent on the economic growth of Switzerland or Korea. For example, Nestle generates only about 3% of its total revenues in Switzerland, and Samsung generates only 14% of its global revenue in South Korea. Also, population growth, destruction during war times, and resource shocks such as the discovery of North Sea oil in the 20th century might influence growth as well as equity market performance of individual countries over extended periods of time (Dimson et al. [2014]).

If smaller companies are less internationally diversified, then the cross-country correlation between small and mid-cap equity market returns and GDP per capita growth should be higher than for large-cap equities, because small and mid-cap equities are typically less dominated by internationally diversified companies. Fama and French [1992] argue that the size premium observed in their data may be due to the higher risk of small-cap stocks because these companies are more exposed to the local economy and have fewer possibilities to shield themselves from this environment.

Although there is increasing evidence that this size premium may have disappeared since its discovery in the early 1980s (Horowitz et al. [2000a, 2000b]), a higher correlation between local economic growth and equity market returns might still exist. In this article, we follow in the footsteps of Ritter [2005] and investigate the correlation across countries between GDP per capita growth and small- and mid-cap equity market returns.

METHODOLOGY

We investigate the equity market returns of 22 developed and 22 emerging markets for large-cap, mid-cap, and small-cap stocks. In order to have consistent market data, we use MSCI indexes for each country, downloaded from Thomson Financial Datastream. MSCI has provided consistent large-cap, mid-cap, and small-cap indexes for these countries since 1994 and for most emerging markets since 1997. Thus, we use annual total returns between 1997 and 2013 as the basis of our investigation. Ritter [2012] has shown that at least for large-cap equities, the resulting cross-country correlation between real total returns in local currencies and real GDP per capita growth is low for both very long time periods spanning more than a century as well as shorter time periods of two decades. Our data sample is shorter than two decades but still covers at least two full business cycles in each country, so that the results should still be representative of a general trend, even though our data is less comprehensive than the data available for large-cap equity market indexes.

In order to calculate real equity market returns and real per capita GDP growth, we use consumer price inflation data and real per capita GDP data from the International Monetary Fund (IMF) available on the IMF website. Since official statistics are released only with some delay, we used IMF estimates for 2012 and 2013 in our analysis.

Low Correlation Prevails for Small- and Mid-Cap Equities

Exhibit 1 summarizes the mean geometric return after inflation in local currencies for the 44 countries under investigation. Data is shown for the MSCI large-cap, mid-cap and small-cap indexes between

EXHIBIT 1

Equity Market Returns and Economic Growth in 44 Countries

	Real Geometric Return in % P.A.					Real Geometric Return in % P.A.			
Country	Large Cap	Mid Cap	Small Cap	GDP/ Capita	Country	Large Cap	Mid Cap	Small Cap	GDP/ Capita
Australia	4.8	2.7	0.6	1.8	Argentina	–24.0	–15.7	n.a.	2.5
Austria	–12.8	–30.7	3.7	1.5	Brazil	1.6	0.0	3.4	1.7
Belgium	–6.6	2.0	0.0	1.1	Chile	2.2	4.1	0.5	2.9
Canada	3.8	6.9	2.6	1.5	China	–9.5	–7.3	0.2	8.5
Denmark	4.1	6.0	–0.7	0.7	Colombia	–4.5	–12.6	–1.0	2.0
Finland	–6.9	3.6	0.9	1.8	Czech Rep.	–0.3	–12.2	–1.0	2.1
France	1.6	4.0	–0.8	0.9	Greece	–26.2	–13.4	n.a.	0.6
Germany	1.1	–1.1	–1.0	1.3	Hungary	–8.1	–39.4	–10.0	2.2
Hong Kong	0.4	–2.9	–0.9	2.7	India	–1.7	–0.4	–4.6	4.8
Ireland	–7.4	–14.3	5.0	2.4	Indonesia	–7.7	–11.0	–22.8	2.3
Italy	–1.2	–0.5	–5.0	0.0	Israel	–0.7	–6.1	n.a.	1.7
Japan	–3.8	–1.5	1.0	0.6	Korea	–0.3	–7.9	–8.5	3.3
Netherlands	0.6	–3.2	–2.9	1.2	Malaysia	–2.3	–3.9	–10.7	2.2
New Zealand	n.a.	4.9	6.2	1.4	Mexico	6.3	–15.0	–2.6	1.1
Norway	2.5	–2.5	–5.3	1.1	Peru	–15.6	–29.5	–7.4	3.3
Portugal	–16.6	–5.8	–2.6	0.7	Philippines	–7.4	–10.5	–14.6	2.4
Singapore	–3.4	–3.6	0.9	2.6	Poland	–10.2	–3.8	–9.9	3.9
Spain	1.6	2.1	0.7	1.1	Russia	–36.4	–60.7	–56.3	4.2
Sweden	1.2	5.2	5.4	1.9	South Africa	5.3	4.5	7.8	1.8
Switzerland	3.7	1.0	1.0	1.1	Taiwan	–3.5	–9.1	–8.8	3.3
U.K.	2.5	3.0	3.0	1.4	Thailand	–9.1	–10.1	–9.2	2.0
USA	2.3	4.2	5.7	1.4	Turkey	–16.0	–13.9	–13.9	2.2

January 1, 1997, and December 31, 2013. We also show the real GDP per capita growth per annum over the same period. Visual inspection shows that the variation between GDP per capita growth and equity market returns is large. Singapore and Hong Kong, for example, show the highest GDP per capita growth of all developed countries but some of the lowest equity market returns, whereas Australia and New Zealand achieved some of the highest equity market returns, with average or below average GDP per capita growth.

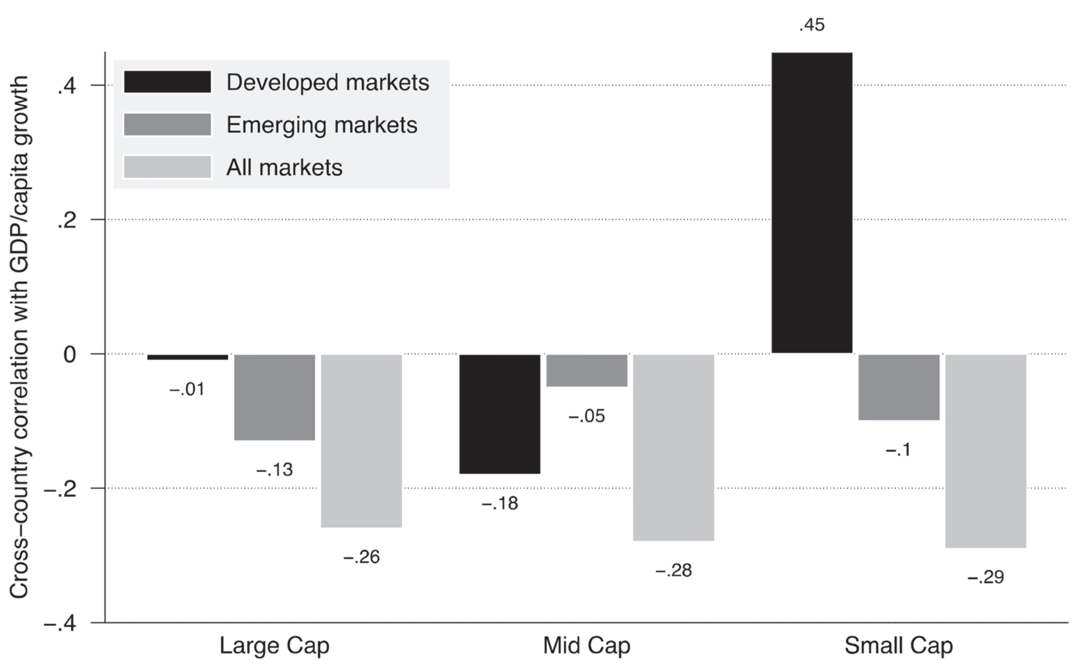
Exhibit 2 shows the resulting cross-country correlations for developed markets, emerging markets, and all 44 markets in our sample. We show correlations for large-cap, mid-cap, and small-cap stock indexes. The cross-country correlation for all size segments is generally comparable in size and—more importantly—negative across all markets. The results for large-cap stock indexes confirm the results of Ritter [2005, 2012] and are generally on the same order of magnitude as his. The results for mid-cap and small-cap equities expand these prior results and show that smaller-size corporations do not offer a higher exposure to local growth. There is a somewhat positive correlation for small-cap stocks in developed countries, but this correlation—just like all the other correlations observed here—is not significantly different from zero. Thus, we are unable to find a meaningful and statistically significant correlation between real stock market returns and real GDP per capita growth for any of our size indexes.

These results are in stark contrast to the rather high positive correlation between valuation measures such as the price-earnings ratio or the cyclically adjusted price-earnings ratio and real equity market returns (Campbell and Shiller [2001] and Klement [2012]). Thus, it seems that stock market returns are predominantly driven by valuations and not economic growth. Investors seem to price in future growth and reflect it in current market valuations no matter whether one looks at large, medium, or small enterprises.

In order to investigate the relationship between global growth and stock market returns, we have also calculated the cross-country correlation with global GDP per capita growth and found no significant correlation. Some countries that are more dependent on exports, like Germany, Italy, Switzerland, or Korea, show higher correlation with global growth than with their local market growth when compared to bigger, more domestically oriented economies like the United

EXHIBIT 2

Cross-Country Correlation between Stock Market Returns and GDP Per Capita Growth



States and India but also China. Nevertheless, these correlations remain small and only slightly positive.

Cross-Country Correlations between Earnings and GDP Per Capita Growth

Even though valuations seem to capture most of the anticipated growth of a country, earnings growth may still be linked to economic growth of a country. Thus, we have calculated real earnings growth for large-cap equities in the 44 countries under investigation here. In Exhibit 3, we show the real earnings growth and the real GDP per capita growth, together with the cross-country correlations between the two variables. Again, the correlations remain close to zero and may even be negative.

Paradoxical as this may sound, there are good reasons why the correlation between earnings growth and real GDP per capita growth may be low across countries. First, earnings growth depends on the growth of productivity as well as the growth in input factors like labor and capital. Thus real earnings growth may be high even when GDP per capita growth is low if a country's population grows rapidly. Dimson et al. [2014] show how countries like Australia, Switzerland, South Africa, or the United States, where immigration and population growth are major determinants of economic growth, profited from these effects. On the other hand, some countries, like Germany or Japan, that have rather limited population growth still enjoyed high real earnings growth in the past, whereas many emerging markets showed low real earnings growth despite high population growth rates. The high real earnings growth despite low population growth and low GDP per capita growth may reflect the ability of enterprises in these regions to capture market shares around the globe at the cost of other local and international competitors. Also, as Bernstein and Arnott [2003] have pointed out, entrepreneurial activities dilute earnings growth because the capital invested in

EXHIBIT 3
Real Earnings Growth and Economic Growth in 44 Countries

Country	Real Earnings Growth in % P.A.	GDP/Capita	Country	Real Earnings Growth in % P.A.	GDP/Capita
Australia	3.5	1.8	Argentina	29.1	2.5
Austria	3.3	1.5	Brazil	–9.1	1.7
Belgium	1.2	1.1	Chile	1.4	2.9
Canada	5.4	1.5	China	3.9	8.5
Denmark	7.0	0.7	Colombia	7.9	2.0
Finland	4.3	1.8	Czech Rep.	n.a.	2.1
France	9.0	0.9	Greece	–5.6	0.6
Germany	6.5	1.3	Hungary	2.1	2.2
Hong Kong	3.1	2.7	India	2.4	4.8
Ireland	–7.4	2.4	Indonesia	2.2	2.3
Italy	0.8	0.0	Israel	n.a.	1.7
Japan	8.2	0.6	Korea	8.8	3.3
Netherlands	1.1	1.2	Malaysia	2.7	2.2
New Zealand	–0.6	1.4	Mexico	5.8	1.1
Norway	n.a.	1.1	Peru	7.1	3.3
Portugal	n.a.	0.7	Philippines	2.9	2.4
Singapore	5.6	2.6	Poland	1.1	3.9
Spain	–2.3	1.1	Russia	7.3	4.2
Sweden	3.6	1.9	South Africa	3.9	1.8
Switzerland	7.0	1.1	Taiwan	n.a.	3.3
U.K.	2.0	1.4	Thailand	–0.7	2.0
USA	3.7	1.4	Turkey	3.6	2.2
Correlation with growth	–0.25		Correlation with growth	+0.13	
Cross-Country Correlation Across All Countries					
Correlation with growth	**+0.09**				

newly founded, nonlisted companies does reduce future earnings growth of listed companies while increasing GDP growth.

We emphasize that these results do not refute the claim that earnings divided by GDP are stationary in large economies like the United States since we look only at cross-country correlations not correlation over time. But it does cast some doubt whether earnings divided by GDP are stationary in small, open economies that have been able to profit from globalization and captured international market share from competitors. After all, if profit margins were stationary for each individual country around the world, earnings should necessarily grow in proportion to GDP over the long run and the correlation between real earnings growth and real GDP growth should be high across countries. The fact that this is not observed indicates that international competition shifts earnings growth between regions.

CONCLUSION

Equity market returns are largely uncorrelated with economic growth across the world, not only for large international companies but also for small- and medium-size enterprises. It seems that independent of size, stock market valuations incorporate future growth expectations into the price of stocks so that correlations between economic growth and stock market returns remain low whereas correlations between valuation measures like the price-earnings ratio and stock market returns are high.

It is likely that in our globalized world, real corporate earnings growth across countries is uncorrelated with GDP per capita growth because international competition, differences in population growth, and differences in competitiveness have a significant influence on the development of real earnings growth as well.

For investors around the world, these findings are good and bad news at the same time. The bad news is that future economic growth seems to matter little for both earnings growth and equity market returns. The good news is that valuations matter and remain the main driver of future stock market returns. All too often, investors overpay for growth by investing in overvalued stocks with exposure to fast-growing markets. However, the real opportunities lie in stocks and stock markets where investors underestimate future growth opportunities.

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By Michael Annin

Equity and the Small-Stock Effect

The capital asset pricing model shows risk inherent in return on equity. But something goes wrong when it's used for small-sized companies.

Does the size of a company affect the rate of return it should earn? If smaller companies should earn a higher return than larger firms, then small utilities, because of their size, should be allowed to adjust the rates they charge to customers.

By far the most notable and well-documented apparent anomaly in the stock market is the effect of company size on equity returns. The first study focusing on the impact that company size exerts on security returns was performed by Rolf W. Banz. Banz sorted New York Stock Exchange (NYSE) stocks into quintiles based on their market capitalization (price per share times number of shares outstanding), and calculated total returns for a value-weighted portfolio of the stocks in each quintile. His results indicate that returns for companies from the smallest quintile surpassed all other quintiles, as well as the Standard & Poor's 500 and other large stock indices. A number of other researchers have replicated Banz's work in other countries; nevertheless, a consensus has not yet been formed on why small stocks behave as they do.

One explanation for the higher returns is the lack of information on small companies. Investors must search more diligently for data. For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.

The Flaw in CAPM

One of the more common cost of equity models used in practice today is the capital asset pricing model (CAPM). The CAPM describes the expected return on any company's stock as proportional to the amount of systematic risk an investor assumes. The traditional CAPM formula can be stated as:

$$R_s = [\beta_s \times RP] + R_f$$

where:

R_s = expected return or cost of equity on the stock of company "s"

β = the *beta* of the stock of company "s"

RP = the expected equity risk premium

R_f = expected return on a riskless asset.

Table 1: The Size Premium in CAPM
(By Decile Portfolio in NYSE, 1926-94)

Decile	*Beta*	Arithmetic Mean Return	Actual Return in Excess of Riskless Rate**	CAPM Return in Excess of Riskless Rate**	Size Premium (Return in Excess CAPM)
1	0.90	11.01%	5.88%	6.33%	–0.44%
2	1.04	13.09	7.97	7.34	0.63
3	1.09	13.83	8.71	7.70	1.01
4	1.13	14.44	9.32	7.98	1.33
5	1.17	15.50	10.38	8.22	2.16
6	1.19	15.45	10.33	8.38	1.95
7	1.24	15.92	10.79	8.75	2.05
8	1.29	16.84	11.72	9.05	2.67
9	1.36	17.83	12.71	9.57	3.14
10	1.47	21.98	16.86	10.33	6.53

*Betas are estimated from monthly returns in excess of the 20-year government bond income return, January 1926-December 1994.
**Historical riskless rate measured by the 69-year arithmetic mean income return component of 20-year government bonds.
Source: SBBI 1995 Yearbook

Table 2: CAPM vs. CAPM w/ Size Premium

(By Percentile for Electric, Gas, and Sanitary Services Utilities)

	CAPM	CAPM with Size Premium
90th Percentile	16.42%	18.92%
75th Percentile	12.56%	14.72%
Median	10.89%	12.58%
25th Percentile	9.86%	11.39%
10th Percentile	8.63%	10.65%

(Weighted by Market Capitalization)

	CAPM	CAPM with Size Premium
Industry Composite	11.76%	12.33%
Large Company Composite	12.05%	12.07%
Small Company Composite	13.93%	17.95%

Source: Cost of Capital Quarterly '95 Yearbook by Ibbotson Associates
Note: Public utilities include electric, gas, and sanitary services companies.

Table 1 shows *beta* and risk premiums over the past 69 years for each decile of the NYSE. It shows that a hypothetical risk premium calculated under the CAPM fails to match the actual risk premium, shown by actual market returns. The shortfall in the CAPM return rises as company size decreases, suggesting a need to revise the CAPM.

The risk premium component in the actual returns (realized equity risk premium) is the return that compensates investors for taking on risk equal to the risk of the market as a whole (estimated by the 69-year arithmetic mean return on large company stocks, 12.2 percent, less the historical riskless rate). The risk premium in the CAPM returns is *beta* multiplied by the realized equity risk premium.

The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premiums (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.

Based on this analysis, we modify the CAPM formula to include a small-stock premium. The modified CAPM formula can be stated as follows:

$$R_s = [\beta_s \times RP] + R_f + SP$$

where:

SP = small-stock premium.

Because the small-stock premium can be identified by company size, the appropriate premium to add for any particular company will depend on its equity capitalization. For instance, a utility with a market capitalization of $1 billion would require a small capitalization adjustment of approximately 1.3 percent over the traditional CAPM; at $400 million, approximately 2.1 percent, and at only $100 million, approximately 4 percent.

Again, these additions to the traditional CAPM represent an adjustment over and above any increase already provided to these smaller companies by having higher *betas*.

Implications for Smaller Utilities

These findings carry important ramifications for relatively small public utilities. Boosting the traditional CAPM return by a full 400 basis points for small utilities translates into a substantial premium over larger utilities.

Table 2 shows the results of an analysis of 202 utility companies that calculated cost of equity figures. Composites (arithmetic means) weighted by equity capitalization were also calculated for the largest and smallest 20 companies. The results show the impact size has on cost of equity.

For the traditional CAPM, the large-company composite shows a cost of equity of 12.05 percent; the small company composite, 13.93 percent. However, once the respective small capitalization premium is added in, the spread increases dramatically, to 12.07 and 17.95 percent, respectively. Clearly, the smaller the utility (in terms of equity capitalization), the larger the impact that size exerts on the expected return of that security. ▼

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BETAS AND THEIR REGRESSION TENDENCIES

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I. INTRODUCTION

A PREVIOUS STUDY [3] showed that estimated beta coefficients, at least in the context of a portfolio of a large number of securities, were relatively stationary over time. Nonetheless, there was a consistent tendency for a portfolio with either an extremely low or high estimated beta in one period to have a less extreme beta as estimated in the next period. In other words, estimated betas exhibited in that article a tendency to regress towards the grand mean of all betas, namely one. This study will examine in further detail this regression tendency.[1]

The next section presents evidence showing the existence of this regression tendency and reviews the conventional reasons given in explanation [1], [4], [5]. The following section develops a formal model of this regression tendency and finds that the conventional analysis of this tendency is, if not incorrect, certainly misleading. Accompanying this theoretical analysis are some new empirical results which show that a major reason for the observed regression is real non-stationarities in the underlying values of beta and that the so-called "order bias" is not of dominant importance.

II. THE CONVENTIONAL WISDOM

If an investor were to use estimated betas to group securities into portfolios spanning a wide range of risk, he would more than likely find that the betas estimated for the very same portfolios in a subsequent period would be less extreme or closer to the market beta of one than his prior estimates. To illustrate, assume that the investor on July 1, 1933, had at his disposal an estimate of beta for each common stock which had been listed on the NYSE (New York Stock Exchange) for the prior seven years, July 1926-June 1933. Assume further that each estimate was derived by regressing the eighty-four monthly relatives covering this seven-year period upon the corresponding values for the market portfolio.[2]

If this investor, say, desired equally weighted portfolios of 100 securities, he might group those 100 securities with the smallest estimates of beta together to form a portfolio. Such a portfolio would of all equally

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1. Quite apart from this regression tendency, it is reasonable to suppose that betas do change over time in systematic ways in response to certain changes in the structure of companies.

2. Such regressions were calculated only for securities with complete data. The relative for the market portfolio was measured by Fisher's Combination Link Relative [6].

weighted portfolios have the smallest possible estimated portfolio beta since an estimate of such a portfolio beta can be shown to be an average of the estimates for the individual securities [2, p. 169]. To cover a wide range of portfolio betas, this investor might then form a second portfolio consisting of the 100 securities with the next smallest estimates of beta, and so on.

Using the securities available as of June 1933, this investor could thus obtain four portfolios of 100 securities apiece with no security in common. Estimated over the same seven-year period, July 1926-June 1933, the betas for these portfolios[3] would have ranged from 0.50 to 1.53. Similar portfolios can be constructed for each of the next seven-year periods through 1954 and their portfolio betas calculated. Table 1 contains these estimates under the heading "Grouping Period."

The betas for these same portfolios, but reestimated using the monthly portfolio relatives adjusted for delistings from the seven years following the grouping period, illustrate the magnitude of the regression tendency.[4] Whereas the portfolio betas as estimated, for instance, in the grouping period 1926-33 ranged from 0.50 to 1.53, the betas as estimated for these same portfolios in the subsequent seven-year period 1933-40 ranged only from 0.61 to 1.42. The results for the other periods display a similar regression tendency.

An obvious explanation of this regression tendency is that for some unstated economic or behavioral reasons, the underlying betas do tend to regress towards the mean over time.[5] Yet, even if the true betas were constant over time, it has been argued that the portfolio betas as estimated in the grouping period would as a statistical artifact tend to be more extreme than those estimated in a subsequent period. This bias has sometimes been termed an order or selection bias.

The frequently given intuitive explanation of this order bias [1], [4], [5], parallels the following: Consider the portfolio formed of the 100 securities with the lowest estimates of beta. The estimated portfolio beta might be expected to understate the true beta or equivalently be expected to be measured with negative error. The reason the measurement error might

3. These portfolio betas were derived by averaging the 100 estimates for the individual securities. Alternatively, as [2] shows, the same number would be obtained by regressing the monthly portfolio relatives upon the market index where the portfolio relatives are calculated assuming an equal amount invested in each security at the beginning of each month.

4. These portfolio betas were calculated by regressing portfolio relatives upon the market relatives. The portfolio relatives were taken to be the average of the monthly relatives of the individual securities for which relatives were available. These relatives represent those which would have been realized from an equally-weighted, monthly rebalancing strategy in which a delisted security is sold at the last available price and the proceeds reinvested equally in the remaining securities. This rather complicated procedure takes into account delisted securities and therefore avoids any survivorship bias. In [3], the securities analyzed were required to be listed on the NYSE throughout both the grouping period and the subsequent period, so that there was a potential survivorship bias. Nonetheless, the results reported there are in substantive agreement with the results in Table 1.

5. If the betas are continually changing over time, an estimate of beta as provided by a simple regression must be interpreted with considerable caution. For example, if the true beta followed a linear time trend, it is easily shown that the estimated beta can be interpreted as an unbiased estimate of the beta in the middle of the sample period. A similar interpretation would not in general hold if, for instance, the true beta followed a quadratic time trend.

TABLE 1
BETA COEFFICIENTS FOR PORTFOLIOS OF 100 SECURITIES

Portfolio	Grouping Period	First Subsequent Period
	7/26-6/33	7/33-6/40
1	0.50	0.61
2	0.85	0.96
3	1.15	1.24
4	1.53	1.42
	7/33-6/40	7/40-6/47
1	0.38	0.56
2	0.69	0.77
3	0.90	0.91
4	1.13	1.12
5	1.35	1.31
6	1.68	1.69
	7/40-6/47	7/47-6/54
1	0.43	0.60
2	0.61	0.76
3	0.73	0.88
4	0.86	0.99
5	1.00	1.10
6	1.21	1.21
7	1.61	1.36
	7/47-6/54	7/54-6/61
1	0.36	0.57
2	0.61	0.71
3	0.78	0.88
4	0.91	0.96
5	1.01	1.03
6	1.13	1.13
7	1.26	1.24
8	1.47	1.32
	7/54-6/61	7/61-6/68
1	0.37	0.62
2	0.56	0.68
3	0.72	0.85
4	0.86	0.85
5	0.99	0.95
6	1.11	0.98
7	1.23	1.07
8	1.43	1.25

be expected to be negative may best be explored by analyzing how a security might happen to have one of the 100 lowest estimates of beta. First, if the true beta were in the lowest hundred, the estimated beta would fall in the lowest 100 estimates only if the error in measuring the beta were not too large which roughly translates into more negative than positive errors. Second, if the true beta were not in the lowest 100, the estimated beta might still be in the lowest 100 estimates if it were measured with a sufficiently large negative error.[6]

Thus, the negative errors in the 100 smallest estimates of beta might be expected to outweigh the positive errors. The same argument except in reverse would apply to the 100 largest estimates. Indeed, it would seem that any portfolio of securities stratified by estimates of beta for which the average of these estimates is not the grand mean of all betas, namely 1.0, would be subject to some order bias. It would also seem that the absolute magnitude of this order bias should be greater, the further the average estimate is from the grand mean. The next section formalizes this intuitive argument and suggests that, if it is not incorrect, it is certainly misleading as to the source of the bias.

III. A Formal Model

The intuitive explanation of the order bias just given would seem to suggest that the way in which the portfolios are formed caused the bias. This section will argue that the bias is present in the estimated betas for the individual securities and is not induced by the way in which the portfolios are selected. Following this argument will be an analysis of the extent to which this order bias accounts for the observed regression tendency in portfolio betas over time.

A numerical example will serve to illustrate the logic of the subsequent argument and to introduce some required notation.[7] Assume for the moment that the possible values of beta for an individual security i in period t, β_{it}, are 0.8, 1.0 and 1.2 and that each of these values is equally likely. Assume further that in estimating a beta for an individual security, there is a 0.6 probability that the estimate $\hat{\beta}_{it}$ contains no measurement error, a 0.2 probability that it understates the true β_{it} by 0.2, and a 0.2 probability that it overstates the true value by 0.2. Now in a sample of ten securities whose true betas were all say 0.8, one would expect two estimates of beta to be 0.6, six to be 0.8, and two to be 1.0. These numbers have been transcribed to the first row of Table 2. The second and third rows are similarly constructed by first assuming that the ten securities all had a true value of 1.0 and then of 1.2.

The rows of Table 2 thus correspond to the distribution of the estimated beta, $\hat{\beta}_{it}$, conditional on the true value, β_{it}. It might be noted that the expectation of $\hat{\beta}_{it}$ conditional on β_{it}, $E(\hat{\beta}_{it} \mid \beta_{it})$, is β_{it}. However, in a sampling situation, an investigator would be faced with an estimate of beta and would want to assess the distribution of the true β_{it} conditional on the estimated $\hat{\beta}_{it}$. Such conditional distributions correspond to the columns of Table 2. It is easily verified that the expectation of β_{it} conditional on $\hat{\beta}_{it}$, $E(\beta_{it} \mid \hat{\beta}_{it})$ is generally not $\hat{\beta}_{it}$. For example, if $\hat{\beta}_{it}$ were

6. It is theoretically possible that the estimated beta for a security whose true beta does not fall into the lowest 100 to be in the lowest 100 estimates with a positive measurement error if the betas for some of the improperly classified securities are measured with sufficiently large positive errors.

7. The author is indebted to Harry Markowitz for suggesting this numerical example as a way of clarifying the subsequent formal development.

TABLE 2
NUMBER OF SECURITIES CROSS CLASSIFIED BY β_{it} AND $\hat{\beta}_{it}$

		$\hat{\beta}_{it}$				
		.6	.8	1.0	1.2	1.4
	.8	2	6	2		
β_{it}	1.0		2	6	2	
	1.2			2	6	2

0.8, $E(\beta_{it} \mid \hat{\beta}_{it} = 0.8)$ would be 0.85 since with this estimate the true beta would be 0.8 with probability 0.75 or 1.0 with probability 0.25.[8]

The estimate $\hat{\beta}_{it}$, therefore, would typically be biased, and it is biased whether or not portfolios are formed. The effect of forming large portfolios is to reduce the random component in the estimate, so that the difference between the estimated portfolio beta and the true portfolio beta can be ascribed almost completely to the magnitude of the bias.

In the spirit of this example, the paper will now develop explicit formulae for the order bias and real non-stationarities over time. Let it be assumed that the betas for individual securities in period t, β_{it}, can be thought of as drawings from a normal distribution with a mean of 1.0 and variance $\sigma^2(\beta_{it})$. The corresponding assumption for the numerical example just discussed would be a trinomial distribution with equal probabilities for each possible value of β_{it}.

Let it additionally be assumed that the estimate, $\hat{\beta}_{it}$, measures β_{it} with error η_{it}, a mean-zero independent normal variate, so that $\hat{\beta}_{it}$ is given by the sum of β_{it} and η_{it}. It immediately follows that β_{it} and $\hat{\beta}_{it}$ are distributed by a bivariate normal distribution. It might be noted that, as formulated, $\sigma^2(\eta_{it})$ need not equal $\sigma^2(\eta_{jt})$, $i \neq j$. Since the empirical work will assume equality, the subsequent theoretical work will also make this assumption even though for the most part it is not necessary. The final assumption is that β_{it} and β_{it+1} are distributed as bivariate normal variates. Because η_{it} is independently distributed, $\hat{\beta}_{it}$ and β_{it+1} will be distributed by a bivariate normal distribution.

That $\hat{\beta}_{it}$ and β_{it+1} are bivariate normal random variables, each with a mean of 1.0, implies the following regression

$$E(\beta_{it+1} \mid \hat{\beta}_{it}) - 1 = \frac{\operatorname{Cov}(\beta_{it+1}, \hat{\beta}_{it})}{\sigma^2(\hat{\beta}_{it})} (\hat{\beta}_{it} - 1). \tag{1}$$

This regression is similar to the procedure proposed in Blume [3] to adjust the estimated betas for the regression tendency. That procedure was to regress estimates of beta for individual securities from a later period on estimates from an earlier period and to use the coefficients from this regression to adjust future estimates.[9] The empirical evidence

8. For further and more detailed discussion of the distinction between $E(\beta_{it} \mid \hat{\beta}_{it})$ and $E(\hat{\beta}_{it} \mid \beta_{it})$, the reader is referred to Vasicek [7].

9. That the regression of estimated betas from a later period on estimates from an earlier period is similar to (1) follows from noting that $E(\hat{\beta}_{it+1} \mid \hat{\beta}_{it})$ equals $E(\beta_{it+1} \mid \hat{\beta}_{it})$ and that $\operatorname{Cov}(\hat{\beta}_{it+1}, \hat{\beta}_{it})$ equals $\operatorname{Cov}(\beta_{it+1}, \hat{\beta}_{it})$. In [3], the grand mean of all betas was estimated in each period and was not assumed equal to 1.0.

presented there indicated that this procedure did improve the accuracy of estimates of future betas, though no claim was made that there might not be better ways to adjust for the regression tendency.

The coefficient of $(\hat{\beta}_{it} - 1)$ in (1) can be broken down into two components: one of which would correspond to the so-called order bias and the other to a true regression tendency. To achieve this result, note that the covariance of β_{it+1} and $\hat{\beta}_{it}$ is given by $\mathrm{Cov}(\beta_{it+1}, \beta_{it} + \eta_{it})$, which because of the assumed independence of the errors, reduces to the covariance of β_{it+1} and β_{it}. Making this substitution and replacing $\mathrm{Cov}(\beta_{it+1}, \beta_{it})$ by $\rho(\beta_{it+1}, \beta_{it})\sigma(\beta_{it+1})\sigma(\beta_{it})$, (1) becomes

$$E(\beta_{it+1} \mid \hat{\beta}_{it}) - 1 = \frac{\rho(\beta_{it+1}, \beta_{it})\sigma(\beta_{it+1})\sigma(\beta_{it})}{\sigma^2(\hat{\beta}_{it})} (\hat{\beta}_{it} - 1). \tag{2}$$

The ratio of $\sigma(\beta_{it})\sigma(\beta_{it+1})$ to $\sigma^2(\hat{\beta}_{it})$ might be identified with the order bias and the correlation of β_{it} and β_{it+1} with a true regression.

If the underlying values of beta are stationary over time, the correlation of successive values will be 1.0 and the standard deviations of β_{it} and β_{it+1} will be the same. Assuming such stationarity and noting then that β_{it+1} equals β_{it}, equation (2) can be rewritten as[10]

$$\begin{aligned} E(\beta_{it+1} \mid \hat{\beta}_{it}) - 1 &= E(\beta_{it} \mid \hat{\beta}_{it}) - 1 \\ &= \frac{\sigma^2(\beta_{it})}{\sigma^2(\hat{\beta}_{it})} (\hat{\beta}_{it} - 1). \end{aligned} \tag{3}$$

Since $\sigma^2(\beta_{it})$ would be less than $\sigma^2(\hat{\beta}_{it})$ if beta is measured with any error, the coefficient of $(\hat{\beta}_{it} - 1)$ would be less than 1.0. This means that the true beta for a security would be expected to be closer to one than the estimated value. In other words, an estimate of beta for an individual security except for an estimate of 1.0 is biased.[11]

10. Equation (3) can be derived alternatively from the assumption that β_{it} and $\hat{\beta}_{it}$ are bivariate normal variables and under the assumption of stationarity β_{it} will equal β_{it+1}. Vasicek [7] has developed using Bayes' Theorem, an expression for $E(\beta_{it}|\hat{\beta}_{it})$ which can be shown to be mathematically identical to the right hand side of (3): He observed that the procedure used by Merrill Lynch, Pierce, Fenner and Smith, Inc. in their Security Risk Evaluation Service is similar to his expression if $\sigma^2(\eta_{it})$ is assumed to be the same for all securities. Merrill Lynch's procedure, as he presented it, is to use the coefficient of the cross-sectional regression of $(\hat{\beta}_{it+1} - 1)$ on $(\hat{\beta}_{it} - 1)$ to adjust future estimates. This adjustment mechanism is in fact the same as (1) or (2) which shows that such a cross sectional regression takes into account real changes in the underlying betas. Only if betas were stationary over time would his formula be similar to Merrill Lynch's.

11. The formula for order bias given by (3) is similar to that which measures the bias in the estimated slope coefficient in a regression on one independent variable measured with error. Explicitly, consider the regression, $y = bx + \epsilon$, where ϵ is an independent mean-zero normal disturbance and both y and x are measured in deviate form. Now if x is measured with independent mean-zero error η and y is regressed on $x + \eta$, it is well known that the estimated coefficient, $\hat{b}$, will be biased toward zero and the probability limit of $\hat{b}$ is $\dfrac{b}{1 + \dfrac{\sigma^2(\eta)}{\sigma^2(x)}}$. This expression can be rewritten as $\dfrac{\sigma^2(x)}{\sigma^2(x + \eta)}$ b. Interpreting x as the true beta less 1.0, the correspondence to (3) is obvious. In this type of regression, one could either adjust the independent variables themselves for bias and thus obtain an unbiased estimate of the regression coefficient or run the regression on the unadjusted variables and then adjust the regression coefficient. The final coefficient will be the same in either case.

In light of this discussion, the paper now reexamines the empirical results of the previous section. The initial task will be to adjust the portfolio betas in the grouping periods for the order bias. After making this adjustment, it will be apparent that much of the regression tendency observed in Table 1 remains. Thus, if (2) is valid, the value of the correlation coefficient is probably not 1.0. The statistical properties of estimates of the portfolio betas in both the grouping and subsequent periods will be examined. The section ends with an additional test that gives further confirmation that much of the regression tendency stems from true non-stationarities in the underlying betas.

To adjust the estimates of beta in the grouping periods for the order bias using (3) would require estimates of the ratio of $\sigma^2(\beta_{it})$ to $\sigma^2(\hat{\beta}_{it})$. The sample variance calculated from the estimated betas for all securities in a particular cross-section provides an estimate of $\sigma^2(\hat{\beta}_{it})$. An estimate of $\sigma^2(\beta_{it})$ can be derived as the difference between estimates of $\sigma^2(\hat{\beta}_{it})$ and $\sigma^2(\eta_{it})$. If the variance of the error in measuring an individual beta is the same for every security, $\sigma^2(\eta_{it})$ can be estimated as the average over all securities of the squares of the standard error associated with each estimated beta.

In conformity with these procedures, estimates of the ratio of $\sigma^2(\beta_{it})$ to $\sigma^2(\hat{\beta}_{it})$ for the five seven-year periods from 1926 through 1961 were respectively 0.92, 0.92, 0.89, 0.82, and 0.75. In other words, an unbiased estimate of the underlying beta for an individual security should be some eight to twenty-five per cent closer to 1.0 than the original estimate. For instance, if $\sigma^2(\beta_{it})/\sigma^2(\hat{\beta}_{it})$ were 0.9 and if $\hat{\beta}_{it}$ were 1.3, an unbiased estimate would be 1.27.

To determine whether the order bias accounted for all of the regression, the estimated betas for the individual securities were adjusted for the order bias using (3) and the appropriate value of the ratio. For the same portfolios of 100 securities examined in the previous section, portfolio betas for the grouping period were recalculated as the average of these adjusted betas. It might be noted that these adjusted portfolio betas could alternatively be obtained by adjusting the unadjusted portfolio betas directly. These adjusted portfolio betas are given in Table 3. For the reader's convenience, the unadjusted portfolio betas and those estimated in the subsequent seven years are reproduced from Table 1.

Before comparing these estimates, let us for the moment consider the statistical properties of the portfolio betas, first in the grouping period and then in the subsequent period. Though unadjusted estimates of the portfolio betas in the grouping period may be biased, they would be expected to be highly "reliable" as that term is used in psychometrics. Thus, regardless of what these estimates measure, they measure it accurately or more precisely their values approximate those which would be expected conditional on the underlying population and how they are calculated. For equally-weighted portfolios, the larger the number of securities, the more reliable would be the estimate.

Specifically, for an equally-weighted portfolio of 100 securities, the standard deviation of the error in the portfolio beta would be one-tenth

TABLE 3
BETA COEFFICIENTS FOR PORTFOLIOS OF 100 SECURITIES

Portfolio	Grouping Period: Unadjusted for Order Bias	Grouping Period: Adjusted for Order Bias	First Subsequent Period	Second Subsequent Period
	7/26-6/33		7/33-6/40	7/40-6/47
1	0.50	.54	0.61	0.73
2	0.85	.86	0.96	0.92
3	1.15	1.14	1.24	1.21
4	1.53	1.49	1.42	1.47
	7/33-6/40		7/40-6/47	7/47-6/54
1	0.38	.43	0.56	0.53
2	0.69	.72	0.77	0.86
3	0.90	.91	0.91	0.96
4	1.13	1.12	1.12	1.11
5	1.35	1.32	1.31	1.29
6	1.68	1.63	1.69	1.40
	7/40-6/47		7/47-6/54	7/54-6/61
1	0.43	.50	0.60	0.73
2	0.61	.65	0.76	0.88
3	0.73	.76	0.88	0.93
4	0.86	.88	0.99	1.04
5	1.00	1.00	1.10	1.12
6	1.21	1.19	1.21	1.14
7	1.61	1.54	1.36	1.20
	7/47-6/54		7/54-6/61	7/61-6/68
1	0.36	.48	0.57	0.72
2	0.61	.68	0.71	0.79
3	0.78	.82	0.88	0.88
4	0.91	.93	0.96	0.92
5	1.01	1.01	1.03	1.04
6	1.13	1.10	1.13	1.02
7	1.26	1.21	1.24	1.08
8	1.47	1.39	1.32	1.15
	7/54-6/61		7/61-6/68	
1	0.37	.53	0.62	
2	0.56	.67	0.68	
3	0.72	.79	0.85	
4	0.86	.89	0.85	
5	0.99	.99	0.95	
6	1.11	1.08	0.98	
7	1.23	1.17	1.07	
8	1.43	1.32	1.25	

the standard error of the estimated betas for individual securities providing the errors in measuring these individual betas were independent of each other. During the 1926-33 period, the average standard error of betas for individual securities was 0.12 so that the standard error of the portfolio beta would be roughly 0.012. The average standard error for individual securities increased gradually to 0.20 in the period July 1954-June 1961. For the next seven-year period ending June 1968, the average declined to 0.17.

As pointed out, standard errors for portfolio betas calculated from those for individual securities assume independence of the errors in estimates. The standard error for a portfolio beta can however be calculated directly without making this assumption of independence by regressing the portfolio returns on the market index. The standard error for the portfolio of the 100 securities with the lowest estimates of beta in the July 1926-June 1933 period was for instance, 0.018, which compares to 0.012 calculated assuming independence. The average standard error of the estimated betas for the four portfolios in this period was also 0.018. The average standard errors of the betas for the portfolios of 100 securities in the four subsequent seven-year periods ending June 1961 were respectively 0.025, 0.027, 0.024, and 0.027. Although these standard errors, not assuming independence, are about 50 per cent larger than before, they are still extremely small compared to the range of possible values for portfolio betas.

For the moment, let us therefore assume that the portfolio betas as estimated in the grouping period before adjustment for order bias are extremely reliable numbers in that whatever they measure, they measure it accurately. In this case, adjusting these portfolio betas for the order bias will give extremely reliable and unbiased estimates of the underlying portfolio beta and therefore these adjusted betas can be taken as very good approximations to the underlying, but unknown, values. The greater the number of securities in the portfolio, the better the approximation will be.

The numerical example in Table 2 gives an intuitive feel for what is happening. Consider a portfolio of a large number of securities whose estimated betas were all 0.8 in a particular sample. It will be recalled that such an estimate requires that the true beta be either 0.8 or 1.0. As the number of securities with estimates of 0.8 increases, one can be more and more confident that 75 per cent of the securities have true betas of 0.8 and 25 per cent have true betas of 1.0 or equivalently that an equally-weighted portfolio of these securities has a beta of 0.85.

The heuristic argument in the prior section might lead some to believe that, contrary to the estimates in the grouping period, there are no order biases associated with the portfolio betas estimated in the subsequent seven years. This belief, however, is not correct. Formally, the portfolios formed in the grouping period are being treated as if they were securities in the subsequent period. To estimate these portfolio betas, portfolio returns were calculated and regressed upon some measure of the market. In this paper so far, these portfolio returns were calculated under an equally-weighted monthly revision strategy in which delisted securities were sold at the last available price and the proceeds reinvested equally in the remaining. Other strategies are, of course, possible.

Since these portfolios are being treated as securities, formula (3) applies, so that there is still some "order bias" present. However, in determining the rate of regression, the appropriate measure of the variance of the errors in the estimates is the variance for the portfolio betas and not for the betas of individual stocks. This fact has the important effect of making the ratio of $\sigma^2(\beta_{it})$ to $\sigma^2(\hat{\beta}_{it})$ much closer to one than for individual securities. Estimating $\sigma^2(\hat{\beta}_{it})$ and $\sigma^2(\eta_{it})$ for the portfolios formed on the immediately prior period, the value of this ratio for each of the four seven-year periods from 1933 to 1961 was in excess of 0.99 and for the last seven-year period in excess of 0.98. Thus, for most purposes, little error is introduced by assuming that these estimated portfolio betas contain no "order bias" or equivalently that these estimates measure accurately the true portfolio beta.

A comparison of the portfolio betas in the grouping period, even after adjusting for the order bias, to the corresponding betas in the immediately subsequent period discloses a definite regression tendency. This regression tendency is statistically significant at the five per cent level for each of the last three grouping periods, 1940-47, 1947-54, 1954-61.[12] Thus, this evidence strongly suggests that there is a substantial tendency for the underlying values of beta to regress towards the mean over time. Yet, it could be argued that this test is suspect because the formula used in adjusting for the order bias was developed under the assumption that the distributions of beta were normal. This assumption is certainly not strictly correct and it is not clear how sensitive the adjustment is to violations of this assumption.

A more robust way to demonstrate the existence of a true regression tendency is based upon the observation that the portfolio betas estimated in the period immediately subsequent to the grouping period are measured with negligible error and bias. These estimated portfolio betas can be compared to betas for the same portfolios estimated in the second seven years subsequent to the grouping period. These betas, which have been estimated in the second subsequent period and are given in Table 3, disclose again an obvious regression tendency. This tendency is significant at the five per cent level for the last three of the four possible comparisons.[13]

IV. Summary

Beginning with a review of the conventional wisdom, the paper showed that estimated beta coefficients tend to regress towards the grand mean of all betas over time. The next section presented two kinds of empirical analyses which showed that part of this observed regression tendency represented real nonstationarities in the betas of individual securities and that the so-called order bias was not of overwhelming importance.

In other words, companies of extreme risk—either high or low—tend to have less extreme risk characteristics over time. There are two logical

12. This test of significance was based upon the regression $(\hat{\beta}_{it+1} - 1) = b(\hat{\beta}_{it} - 1) + \epsilon_{it}$ where $\hat{\beta}_{it}$ has been adjusted for order bias. The estimated coefficients with the t-value measured from 1.0 in parentheses were for the five seven-years chronologically 0.86 (−1.14), 0.94 (−0.88), 0.71 (−3.84), 0.86 (−3.23), and 0.81 (−2.57). Note that even if β_{it} were measured with substantial independent error contrary to fact, the estimated b would not be biased towards zero because, as footnote 10 shows, the adjustment for the order bias has already corrected for this bias.

13. Using the same regression as in the previous footnote, the estimated coefficient b with the t-value measured from 1.0 in parentheses were for the four possible comparisons in chronological order 0.92 (−0.69), 0.74 (−2.67), 0.62 (−6.86), and 0.58 (−5.51).

explanations. First, the risk of existing projects may tend to become less extreme over time. This explanation may be plausible for high risk firms, but it would not seem applicable to low risk firms. Second, new projects taken on by firms may tend to have less extreme risk characteristics than existing projects. If this second explanation is correct, it is interesting to speculate on the reasons. For instance, is it a management decision or do limitations on the availability of profitable projects of extreme risk tend to cause the riskiness of firms to regress towards the grand mean over time? Though one could continue to speculate on the forces underlying this tendency of risk—as measured by beta coefficients—to regress towards the grand mean over time, it remains for future research to determine the explicit reasons.

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Stocks, Bonds, Bills, and Inflation

SBBI

Valuation Edition
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IbbotsonAssociates

Finnerty and Leistikow perform more econometrically sophisticated tests of mean reversion in the equity risk premium. Their tests demonstrate that—as we suspected from our simpler tests—the equity risk premium that was realized over 1926 to the present was almost perfectly free of mean reversion and had no statistically identifiable time trends.[4] Lo and MacKinlay conclude, "the rejection of the random walk for weekly returns does not support a mean-reverting model of asset prices."

Choosing an Appropriate Historical Period

The estimate of the equity risk premium depends on the length of the data series studied. A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable.[5] Furthermore, because an average of the realized equity risk premium is quite volatile when calculated using a short history, using a long series makes it less likely that the analyst can justify any number he or she wants. The magnitude of how shorter periods can affect the result will be explored later in this chapter.

Some analysts estimate the expected equity risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain "unusual" events. Some of the most unusual events of this century took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, and the development of the European Economic Community—all of these happened approximately in the last 30 years.

It is even difficult for economists to predict the economic environment of the future. For example, if one were analyzing the stock market in 1987 before the crash, it would be statistically improbable to predict the impending short-term volatility without considering the stock market crash and market volatility of the 1929–1931 period.

Without an appreciation of the 1920s and 1930s, no one would believe that such events could happen. The 79-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific

4 Though the study performed by Finnerty and Leistikow demonstrates that the traditional equity risk premium exhibits no mean reversion or drift, they conclude that, "the processes generating these risk premiums are generally mean-reverting." This conclusion is completely unrelated to their statistical findings and has received some criticism. In addition to examining the traditional equity risk premia, Finnerty and Leistikow include analyses on "real" risk premia as well as separate risk premia for income and capital gains. In their comments on the study, Ibbotson and Lummer show that these "real" risk premia adjust for inflation twice, "creating variables with no economic content." In addition, separating income and capital gains does not shed light on the behavior of the risk premia as a whole.

5 This assertion is further corroborated by data presented in *Global Investing: The Professional's Guide to the World of Capital Markets* (by Roger G. Ibbotson and Gary P. Brinson and published by McGraw-Hill, New York). Ibbotson and Brinson constructed a stock market total return series back to 1790. Even with some uncertainty about the accuracy of the data before the mid-nineteenth century, the results are remarkable. The real (adjusted for inflation) returns that investors received during the three 50-year periods and one 51-year period between 1790 and 1990 did not differ greatly from one another (that is, in a statistically significant amount). Nor did the real returns differ greatly from the overall 201-year average. This finding implies that because real stock-market returns have been reasonably consistent over time, investors can use these past returns as reasonable bases for forming their expectations of future returns.

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

Any forward-looking cost of capital calculation already embodies tax effects since investors price securities on the basis of after-tax returns. Besides, a very large proportion of trading is conducted by tax-exempt financial institutions (pension funds, mutual funds, 401K, etc.) for whom tax issues are largely immaterial.

The existence of a negative risk premium is highly unlikely, as it is at serious odds with the basic tenets of finance, economics, and law. Using proper definitions for expected rates of return of equity and debt, the preponderance of the evidence indicates that the negative risk premium does not exist. Several risk premium studies cited in this chapter have found positive risk premiums well in excess of 5% over the last decade. Risk premiums do narrow during unusually turbulent and volatile interest rate environments, but then return to normal levels. They are most unlikely to ever become negative.

4.7 Risk Premium Determinants

Fundamentally, the primary determinant of expected returns is risk. To wit, the various paradigms of financial theory, including the Capital Asset Pricing Model and the Arbitrage Pricing Model covered in subsequent chapters, posit fundamental relationships between return and risk. There are also secondary influences on the relative magnitude of the risk premium, however, including the level of interest rates, default risk, and taxes.

Interest Rates

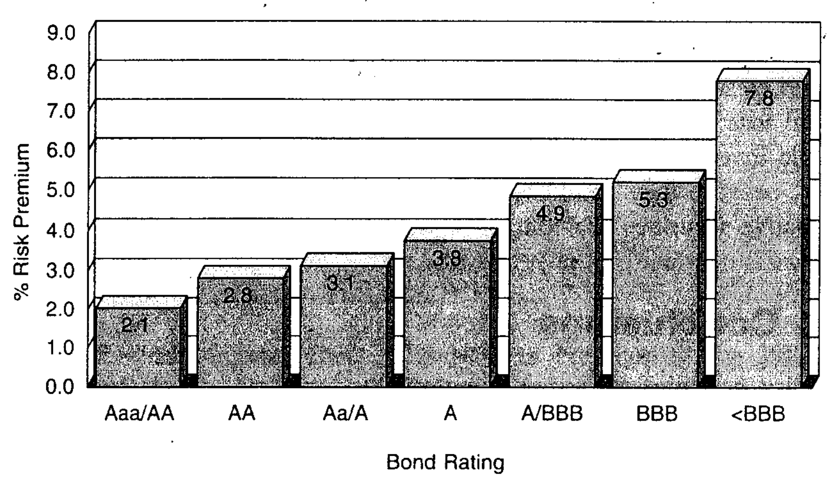
Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin, (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when interest rates rose. The reason for this relationship is that when interest rates rise, bondholders suffer a capital loss. This is referred to as interest rate risk. Stockholders, on the other hand, are more concerned with the firm's earning power. So, if bondholders' fear of interest rate risk exceeds shareholders' fear of loss of earning power, the risk differential will narrow and hence the risk premium will shrink. This is particularly true in high inflation environments. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings risk of common stocks, which are partially hedged from the ravages of inflation. This phenomenon has been termed as a "lock-in" premium. Conversely in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase.

Harris (1986) showed that for every 100 basis point change in government bond yields, the equity risk premium for utilities changes 51 basis points in the opposite direction, for a net change in the cost of equity of 49 basis points. For example, a 100 basis point decline in government bond yields would lead to a 51 basis point increase in the equity risk premium and therefore an overall decrease in the cost of equity of 49 basis points, a result almost identical to the estimate reported in Morin (2005). As discussed earlier, similar results were uncovered by McShane (2005), who examined the statistical relationship between DCF-derived risk premiums and interest rates using a sample of natural gas distribution utilities.

The gist of the empirical research on this subject is that the cost of equity has changed only half as much as interest rates have changed in the past. The knowledge that risk premiums vary inversely to the level of interest rates can be used to adjust historical risk premiums to better reflect current market conditions. Thus, when interest rates are unusually high (low), the appropriate current risk premium is somewhat below (above) that long-run average. The empirical research cited above provides guidance as to the magnitude of the adjustment.

Risk premiums also tend to fluctuate with changes in investor risk aversion. Such changes can be tracked by observing the yield spreads between different bond rating categories over time. Brigham, Shome, and Vinson (1985) examined the relationship between risk premium and bond rating and found, unsurprisingly, that the risk premiums are higher for lower rated firms than for higher rated firms. Figure 4-5 shows the results graphically.

FIGURE 4-5
RISK PREMIUMS VS BOND RATINGS
ELECTRIC UTILITIES



Source: Brigham, Shome, and Vinson (1985).

to the DCF method, which may be sluggish in detecting changes in return requirements, especially when based on historical data.

One advantage of risk premium over DCF is that the former is a period-by-period (time-series) study of the cost of equity over the cost of debt, in contrast to the latter which is a point-in-time cross-sectional estimate. In other words, the risk premium approach takes a broader time-series perspective rather than a snapshot point-in-time viewpoint, and is therefore less vulnerable to the vagaries of any one particular capital market environment. A prospective risk premium test relies on a succession of DCF observations over long periods, and is not as vulnerable to a given capital market environment as a spot DCF test.

Of course, the estimation of the appropriate risk premium for either the equity market as a whole or for a specific utility company, is not an exact science. Therefore, it is necessary to evaluate a broad spectrum of data and apply alternative risk premium estimation approaches in order to derive a fair and reasonable estimate of the required equity risk premium. Equal emphasis should be accorded to risk premium results based on history and those based on prospective data. Each proxy for expected risk premium brings information to the judgment process from a different light. Neither proxy is without blemish, each has advantages and shortcomings. Historical risk premiums over long periods are available and verifiable, but may no longer be applicable if structural shifts have occurred. Prospective risk premiums may be more relevant since they encompass both history and current changes, but are nevertheless imperfect proxies and are subject to measurement error and to the vagaries of the DCF input proxies.

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S&P Global
Market Intelligence

October 26, 2017
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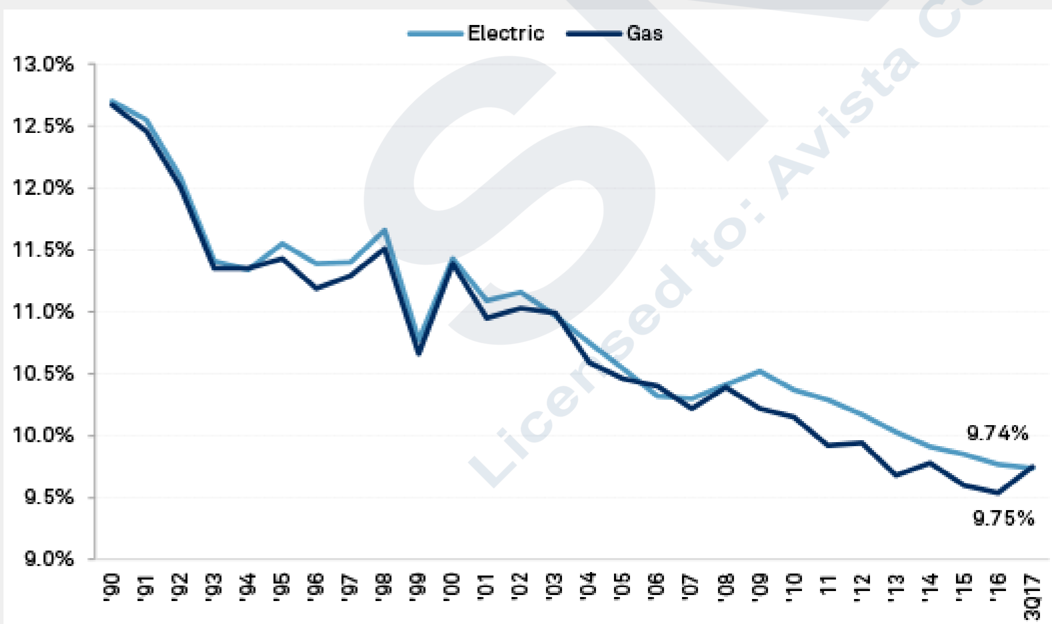
RRA Regulatory Focus

Major Rate Case Decisions January-September 2017

The average ROE authorized electric utilities was 9.74% in rate cases decided in the first three quarters of 2017, compared to 9.77% in full year 2016. There were 34 electric ROE determinations in the first nine months of 2017, versus 42 in 2016. This data includes several limited issue rider cases; excluding these cases from the data, the average authorized ROE was 9.63% in rate cases decided in the first three quarters of 2017, virtually identical to the 9.6% in full year 2016. RRA notes that this differential in electric authorized ROEs is largely driven by Virginia statutes that authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects (see the Virginia Commission Profile).

The average ROE authorized gas utilities was 9.75% in the first nine months of 2017 versus 9.54% in 2016. There were 16 gas cases that included an ROE determination in the first three quarters of 2017, versus 26 in full year 2016. RRA notes that the year to date gas data includes an 11.88% ROE determination for an Alaska utility. Absent this "outlier," the 2017 year to date gas ROE average is 9.61%.

Average authorized ROEs — electric and gas rate decisions

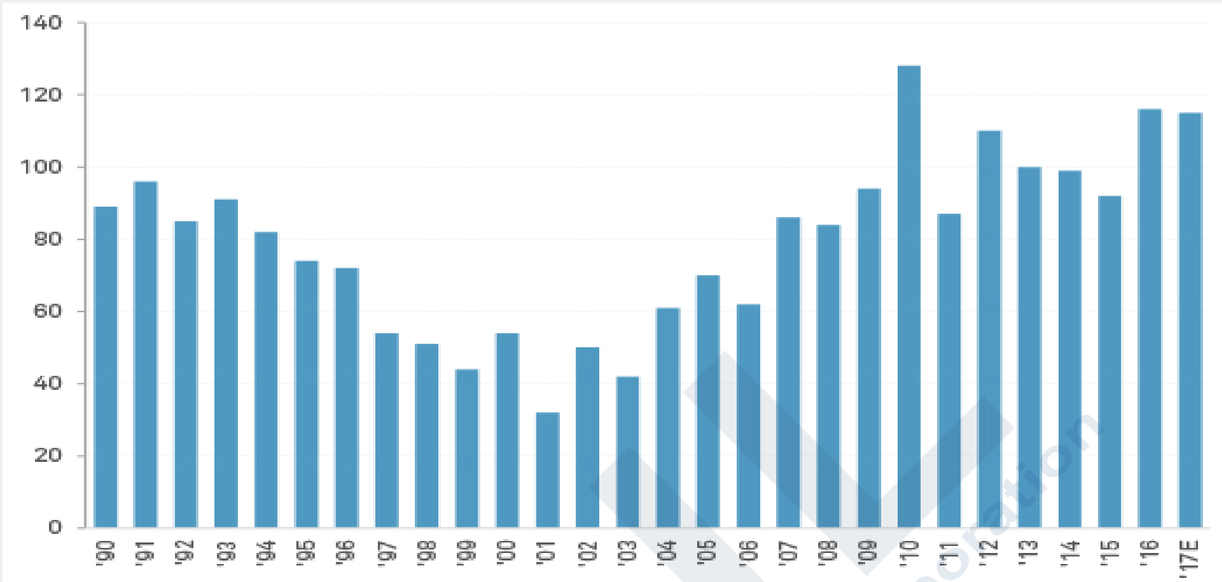


Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

As shown in the graph on the top of page 2, after reaching a low in the early-2000s, the number of rate case decisions for energy companies has generally increased over the last several years, peaking in 2010 at more than 125 cases.

Since 2010, the number of rate cases has moderated somewhat but has been 90 or more in the last five calendar years. There were 116 electric and gas rate cases resolved in 2016, 92 in 2015, 99 in 2014, 100 in 2013, and 110 in 2012, and this level of rate case activity remains robust compared to the late 1990s/early 2000s. Increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates and employee benefits argue for the continuation of an active rate case agenda over the next few years.

Volume of electric and gas rate case decisions



Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

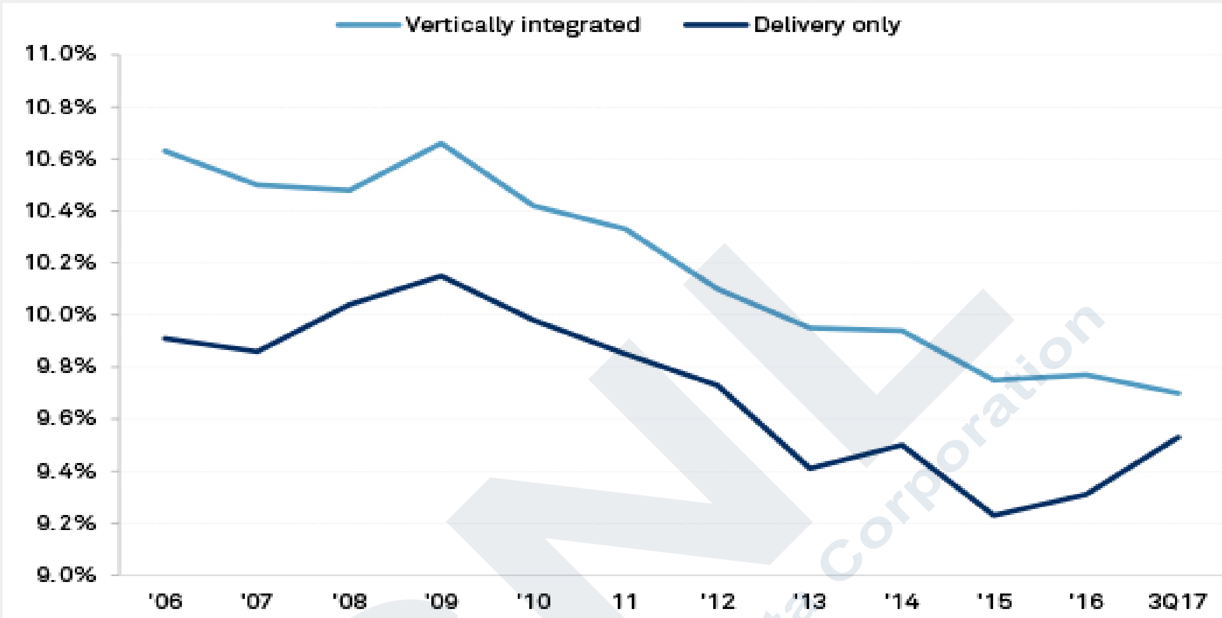
In addition, if the Federal Reserve continues its policy initiated in December 2015 to gradually raise the federal funds rate, utilities eventually would face higher capital costs and would need to initiate rate cases to reflect the higher capital costs in rates. While the Fed has continued to raise the federal funds rate during 2017, the magnitude and pace of any additional action after this year is especially uncertain. An increase in the rate of price inflation would point to additional Fed tightening, but a significant weakening in the economy would likely cause the Fed to reconsider further interest rate hikes. Also, higher interest rates and borrowing costs would increase the U.S. budget deficit, which is already quite significant.

Included in tables on pages 6 and 7 of this report are comparisons, since 2006, of average authorized ROEs by settled versus fully litigated cases, general rate cases versus limited issue rider proceedings and vertically integrated cases versus delivery only cases. For both electric and gas cases, no pattern exists in average annual authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others it was higher for settled cases, and in a few years the authorized ROE was similar for fully litigated versus settled cases. Regarding electric cases that involve limited issue riders, over the last several years the annual average authorized ROEs in these cases was typically at least 70 basis points higher than in general rate cases, driven by the ROE premiums authorized in Virginia. Limited issue rider cases in which an ROE is determined have had extremely limited use in the gas industry. Comparing electric vertically integrated cases versus delivery only proceedings, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are from roughly 40 to 70 basis points higher than in delivery only cases, arguably reflecting the increased risk associated with generation assets.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the cases decided in the specified time periods and are not necessarily representative of the returns actually earned by utilities industry wide.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations, which we footnote in our chronology beginning on page 8, thus complicating historical data comparability. RRA notes that from 2008 through 2015, interest rates declined significantly, and average authorized ROEs have declined modestly. Also, limited issue rider proceedings that allow utilities to recover certain costs outside of a general rate case and typically incorporate previously determined return parameters have been increasingly utilized.

Average authorized electric ROEs



Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

The table on page 4 shows the average ROE authorized in major electric and gas rate decisions annually since 1990, and by quarter since 2014, followed by the number of observations in each period. The tables on page 5 indicate the composite electric and gas industry data for all major cases summarized annually since 2003 and by quarter for the past seven quarters. The individual electric and gas cases decided in 2017 are listed on pages 8-13, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, or ROR, ROE, and percentage of common equity in the adopted capital structure. Next, we indicate the month and year in which the adopted test year ended, whether the commission utilized an average or a year end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

Please Note: Historical data provided in this report may not match data provided on RRA's website due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

Average ROEs authorized January 1990 - September 2017

		Electric utilities		Gas utilities	
Year	Period	ROE (%)	No. of Cases	ROE (%)	No. of Cases
1990	Full year	12.70	(44)	12.67	(31)
1991	Full year	12.55	(45)	12.46	(35)
1992	Full year	12.09	(48)	12.01	(29)
1993	Full year	11.41	(32)	11.35	(45)
1994	Full year	11.34	(31)	11.35	(28)
1995	Full year	11.55	(33)	11.43	(16)
1996	Full year	11.39	(22)	11.19	(20)
1997	Full year	11.40	(11)	11.29	(13)
1998	Full year	11.66	(10)	11.51	(10)
1999	Full year	10.77	(20)	10.66	(9)
2000	Full year	11.43	(12)	11.39	(12)
2001	Full year	11.09	(18)	10.95	(7)
2002	Full year	11.16	(22)	11.03	(21)
2003	Full year	10.97	(22)	10.99	(25)
2004	Full year	10.75	(19)	10.59	(20)
2005	Full year	10.54	(29)	10.46	(26)
2006	Full year	10.32	(26)	10.40	(15)
2007	Full year	10.30	(38)	10.22	(35)
2008	Full year	10.41	(37)	10.39	(32)
2009	Full year	10.52	(40)	10.22	(30)
2010	Full year	10.37	(61)	10.15	(39)
2011	Full year	10.29	(42)	9.92	(16)
2012	Full year	10.17	(58)	9.94	(35)
2013	Full year	10.03	(49)	9.68	(21)
	1st quarter	10.23	(8)	9.54	(6)
	2nd quarter	9.83	(5)	9.84	(8)
	3rd quarter	9.87	(12)	9.45	(6)
	4th quarter	9.78	(13)	10.28	(6)
2014	**Full year**	**9.91**	**(38)**	**9.78**	**(26)**
	1st quarter	10.37	(9)	9.47	(3)
	2nd quarter	9.73	(7)	9.43	(3)
	3rd quarter	9.40	(2)	9.75	(1)
	4th quarter	9.62	(12)	9.68	(9)
2015	**Full year**	**9.85**	**(30)**	**9.60**	**(16)**
	1st quarter	10.29	(9)	9.48	(6)
	2nd quarter	9.60	(7)	9.42	(6)
	3rd quarter	9.76	(8)	9.47	(4)
	4th quarter	9.57	(18)	9.68	(10)
2016	**Full year**	**9.77**	**(42)**	**9.54**	**(26)**
	1st quarter	9.87	(15)	9.60	(3)
	2nd quarter	9.63	(14)	9.47	(7)
	3rd quarter	9.66	(5)	10.14	(6)
2017	**Year-to-date**	**9.74**	**(34)**	**9.75**	**(16)**

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric utilities — summary table

	Period	ROR (%)	No. of cases	ROE (%)	No. of cases	Capital structure	No. of cases	$M	No. of cases
2003	Full year	8.86	(20)	10.97	(22)	49.41	(19)	313.8	(12)
2004	Full year	8.44	(18)	10.75	(19)	46.84	(17)	1,091.5	(30)
2005	Full year	8.30	(26)	10.54	(29)	46.73	(27)	1,373.7	(36)
2006	Full year	8.32	(26)	10.32	(26)	48.54	(25)	1,318.1	(39)
2007	Full year	8.18	(37)	10.30	(38)	47.88	(36)	1,405.7	(43)
2008	Full year	8.21	(39)	10.41	(37)	47.94	(36)	2,823.2	(44)
2009	Full year	8.24	(40)	10.52	(40)	48.57	(39)	4,191.7	(58)
2010	Full year	8.01	(62)	10.37	(61)	48.63	(57)	4,921.9	(78)
2011	Full year	8.00	(43)	10.29	(42)	48.26	(42)	2,595.1	(56)
2012	Full year	7.95	(51)	10.17	(58)	50.69	(52)	3,080.7	(69)
2013	Full year	7.66	(45)	10.03	(49)	49.25	(43)	3,328.6	(61)
2014	Full year	7.60	(32)	9.91	(38)	50.28	(35)	2,053.7	(51)
2015	Full year	7.38	(35)	9.85	(30)	49.54	(30)	1,891.5	(52)
	1st quarter	7.03	(9)	10.29	(9)	46.06	(9)	311.2	(12)
	2nd quarter	7.42	(7)	9.60	(7)	49.91	(7)	117.7	(9)
	3rd quarter	7.23	(8)	9.76	(8)	49.11	(8)	499.3	(13)
	4th quarter	7.38	(17)	9.57	(18)	49.93	(17)	1,403.9	(23)
2016	**Full year**	**7.28**	**(41)**	**9.77**	**(42)**	**48.91**	**(41)**	**2,332.1**	**(57)**
	1st quarter	6.97	(15)	9.87	(15)	47.95	(15)	1,015.8	(23)
	2nd quarter	7.11	(9)	9.63	(14)	48.77	(9)	597.0	(19)
	3rd quarter	7.43	(5)	9.66	(5)	49.63	(5)	558.6	(10)
2017	**Year-to-date**	**7.09**	**(29)**	**9.74**	**(34)**	**48.50**	**(29)**	**2,171.4**	**(52)**

Gas utilities — summary table

	Period	ROR (%)	No. of cases	ROE (%)	No. of cases	Capital structure	No. of cases	$M	No. of cases
2003	Full year	8.75	(22)	10.99	(25)	49.93	(22)	260.1	(30)
2004	Full year	8.34	(21)	10.59	(20)	45.90	(20)	303.5	(31)
2005	Full year	8.25	(29)	10.46	(26)	48.66	(24)	458.4	(34)
2006	Full year	8.44	(17)	10.40	(15)	47.24	(16)	392.5	(23)
2007	Full year	8.11	(31)	10.22	(35)	48.47	(28)	645.3	(43)
2008	Full year	8.49	(33)	10.39	(32)	50.35	(32)	700.0	(40)
2009	Full year	8.15	(29)	10.22	(30)	48.49	(29)	438.6	(36)
2010	Full year	7.99	(40)	10.15	(39)	48.70	(40)	776.5	(50)
2011	Full year	8.09	(18)	9.92	(16)	52.49	(14)	367.0	(31)
2012	Full year	7.98	(30)	9.94	(35)	51.13	(32)	264.0	(41)
2013	Full year	7.43	(21)	9.68	(21)	50.60	(20)	498.7	(39)
2014	Full year	7.65	(27)	9.78	(26)	51.11	(28)	529.2	(48)
2015	Full year	7.34	(16)	9.60	(16)	49.93	(16)	494.1	(40)
	1st quarter	7.12	(6)	9.48	(6)	50.83	(6)	120.2	(11)
	2nd quarter	7.38	(6)	9.42	(6)	50.01	(6)	276.3	(16)
	3rd quarter	6.59	(5)	9.47	(4)	48.44	(4)	106.3	(8)
	4th quarter	7.11	(11)	9.68	(10)	50.27	(10)	761.1	(24)
2016	**Full year**	**7.08**	**(28)**	**9.54**	**(26)**	**50.06**	**(26)**	**1,263.9**	**(59)**
	1st quarter	7.20	(2)	9.60	(3)	51.57	(3)	60.6	(7)
	2nd quarter	7.27	(5)	9.47	(7)	49.15	(5)	85.2	(13)
	3rd quarter	7.07	(8)	10.14	(6)	46.58	(7)	115.9	(15)
2017	**Year-to-date**	**7.15**	**(15)**	**9.75**	**(16)**	**48.43**	**(15)**	**261.8**	**(35)**

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric average authorized ROEs: 2006 — 2017 year-to-date

Settled versus fully litigated cases

	All cases		Settled cases		Fully litigated cases	
Year	ROE (%)	(No. of cases)	ROE (%)	(No. of cases)	ROE (%)	(No. of cases)
2006	10.32	(26)	10.26	(11)	10.37	(15)
2007	10.30	(38)	10.42	(14)	10.23	(24)
2008	10.41	(37)	10.43	(17)	10.39	(20)
2009	10.52	(40)	10.64	(16)	10.45	(24)
2010	10.37	(61)	10.39	(34)	10.35	(27)
2011	10.29	(42)	10.12	(16)	10.39	(26)
2012	10.17	(58)	10.06	(29)	10.28	(29)
2013	10.03	(49)	10.12	(32)	9.85	(17)
2014	9.91	(38)	9.73	(17)	10.05	(21)
2015	9.85	(30)	10.07	(14)	9.66	(16)
2016	9.77	(42)	9.80	(17)	9.74	(25)
2017 YTD	9.74	(34)	9.61	(18)	9.89	(16)

General rate cases versus limited issue riders

	All cases		General rate cases		Limited issue riders	
Year	ROE (%)	No. of cases	ROE (%)	No. of cases	ROE (%)	No. of cases
2006	10.32	(26)	10.34	(25)	9.80	(1)
2007	10.30	(38)	10.31	(37)	9.90	(1)
2008	10.41	(37)	10.37	(35)	11.11	(2)
2009	10.52	(40)	10.52	(38)	10.55	(2)
2010	10.37	(61)	10.29	(58)	11.87	(3)
2011	10.29	(42)	10.19	(40)	12.30	(2)
2012	10.17	(58)	10.01	(52)	11.57	(6)
2013	10.03	(49)	9.81	(42)	11.34	(7)
2014	9.91	(38)	9.75	(33)	10.96	(5)
2015	9.85	(30)	9.60	(24)	10.87	(6)
2016	9.77	(42)	9.60	(32)	10.31	(10)
2017 YTD	9.74	(34)	9.63	(24)	10.01	(10)

Vertically integrated cases versus delivery only cases

	All cases		Vertically integrated cases		Delivery only cases	
Year	ROE (%)	No. of cases	ROE (%)	No. of cases	ROE (%)	No. of cases
2006	10.32	(26)	10.63	(15)	9.91	(10)
2007	10.30	(38)	10.50	(26)	9.86	(11)
2008	10.41	(37)	10.48	(26)	10.04	(9)
2009	10.52	(40)	10.66	(28)	10.15	(10)
2010	10.37	(61)	10.42	(41)	9.98	(17)
2011	10.29	(42)	10.33	(28)	9.85	(12)
2012	10.17	(58)	10.10	(39)	9.73	(13)
2013	10.03	(49)	9.95	(31)	9.41	(11)
2014	9.91	(38)	9.94	(19)	9.50	(14)
2015	9.85	(30)	9.75	(17)	9.23	(7)
2016	9.77	(42)	9.77	(20)	9.31	(12)
2017 YTD	9.74	(34)	9.70	(14)	9.53	(10)

YTD = year-to-date, through Sept. 30, 2017
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas average authorized ROEs: 2006 — 2017 year-to-date

Settled versus fully litigated cases

	All cases		Settled cases		Fully litigated cases	
Year	ROE (%)	No. of cases	ROE (%)	No. of cases	ROE (%)	No. of cases
2006	10.40	(15)	10.26	(7)	10.53	(8)
2007	10.22	(35)	10.24	(22)	10.20	(13)
2008	10.39	(32)	10.34	(20)	10.47	(12)
2009	10.22	(30)	10.43	(13)	10.05	(17)
2010	10.15	(39)	10.30	(12)	10.08	(27)
2011	9.92	(16)	10.08	(8)	9.76	(8)
2012	9.94	(35)	9.99	(14)	9.92	(21)
2013	9.68	(21)	9.80	(9)	9.59	(12)
2014	9.78	(26)	9.51	(11)	9.98	(15)
2015	9.60	(16)	9.60	(11)	9.58	(5)
2016	9.54	(26)	9.50	(16)	9.61	(10)
2017 YTD	9.75	(16)	9.68	(11)	9.89	(5)

General rate cases versus limited issue riders

	All cases		General rate cases		Limited issue riders	
Year	ROE (%)	No. of cases	ROE (%)	No. of cases	ROE (%)	No. of cases
2006	10.40	(15)	10.40	(15)	—	(0)
2007	10.22	(35)	10.22	(35)	—	(0)
2008	10.39	(32)	10.39	(32)	—	(0)
2009	10.22	(30)	10.22	(30)	—	(0)
2010	10.15	(39)	10.15	(39)	—	(0)
2011	9.92	(16)	9.91	(15)	10.00	(1)
2012	9.94	(35)	9.93	(34)	10.40	(1)
2013	9.68	(21)	9.68	(21)	—	(0)
2014	9.78	(26)	9.78	(26)	—	(0)
2015	9.60	(16)	9.60	(16)	—	(0)
2016	9.54	(26)	9.53	(25)	9.70	(1)
2017 YTD	9.75	(16)	9.75	(16)	—	(0)

YTD = year-to-date, through Sept. 30, 2017

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Amt. ($M)	Footnotes
1/10/17	Empire District Electric Company	KS	—	—	—	—	—	—	(1)
1/12/17	Electric Transmission Texas	TX	6.39	9.60	40.00	12/16	Year-end	-46.2	(Tr,B)
1/17/17	Cross Texas Transmission	TX	—	—	—	—	—	-6.5	(Tr,B)
1/18/17	MDU Resources Group, Inc.	WY	7.25	9.45	50.99	12/15	Year-end	2.7	(B)
1/19/17	Metropolitan Edison Company	PA	—	—	—	12/17	—	90.5	(D,B)
1/19/17	Pennsylvania Electric Company	PA	—	—	—	12/17	—	94.6	(D,B)
1/19/17	Pennsylvania Power Company	PA	—	—	—	12/17	—	27.5	(D,B)
1/19/17	West Penn Power Company	PA	—	—	—	12/17	—	60.6	(D,B)
1/24/17	Consolidated Edison Co. of NY	NY	6.82	9.00	48.00	12/17	Average	194.5	(D,B)
1/25/17	Northern Indiana Public Service Co.	IN	—	—	—	4/16	Year-end	1.9	(LIR,B,2)
1/26/17	Southwestern Public Service Co.	TX	—	—	—	9/15	Year-end	35.2	(B)
1/31/17	DTE Electric Company	MI	5.55	10.10	37.49	7/17	Average	184.3	(I,*)
2/15/17	Delmarva Power & Light Company	MD	6.74	9.60	49.10	3/16	Average	38.3	(D)
2/22/17	Rockland Electric Company	NJ	7.47	9.60	49.70	12/16	Year-end	1.7	(D,B)
2/24/17	Indianapolis Power & Light Company	IN	—	—	—	—	—	—	(1)
2/24/17	Tucson Electric Power Company	AZ	7.04	9.75	50.03	6/15	Year-end	81.5	(B)
2/27/17	Virginia Electric and Power Company	VA	7.73	11.40	49.49	3/18	Average	-2.4	(LIR,3)
2/27/17	Virginia Electric and Power Company	VA	6.74	9.40	49.49	3/18	Average	41.4	(LIR,4)
2/27/17	Virginia Electric and Power Company	VA	7.24	10.40	49.49	3/18	Average	-2.2	(LIR,5)
2/27/17	Virginia Electric and Power Company	VA	7.24	10.40	49.49	3/18	Average	-8.5	(LIR,6)
2/27/17	Virginia Electric and Power Company	VA	7.24	10.40	49.49	3/18	Average	0.5	(LIR,7)
2/28/17	Consumers Energy Company	MI	5.94	10.10	40.75	8/17	Average	113.3	(I,*)
3/2/17	Otter Tail Power Company	MN	7.51	9.41	52.50	12/16	Average	12.3	(I)
3/8/17	Union Electric Company	MO	—	—	—	3/16	—	92.0	(B)
3/20/17	Oklahoma Gas and Electric Co.	OK	7.69	9.50	53.31	6/15	Year-end	8.8	(I)
2017	**1st quarter: averages/total**		**6.97**	**9.87**	**47.95**			**1,015.8**	
	Observations		**15**	**15**	**15**			**23**	
4/4/17	Gulf Power Company	FL	—	10.25	—	12/17	—	62.0	(B)
4/12/17	Liberty Utilities (Granite State Electric)	NH	7.64	9.40	50.00	12/15	—	3.8	(D,IB,Z)
4/19/17	Southwestern Public Service Company	NM	—	—	—	—	—	0.0	(8)
4/20/17	Unitil Energy Systems, Inc.	NH	8.34	9.50	50.97	12/15	—	4.1	(D,IB,Z)

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric utility decisions (continued)

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Amt. ($M)	Footnotes
5/3/17	Kansas City Power & Light Company	MO	7.43	9.50	49.20	12/15	Year-end	32.5	
5/11/17	Pacific Gas and Electric Company	CA	—	—	—	12/17	Average	91.0	(B,Z)
5/11/17	Appalachian Power Company	VA	—	—	—	6/18	Average	4.7	(B,LIR,9)
5/11/17	Northern States Power Company - MN	MN	7.08	9.20	52.50	12/19	Average	244.7	(B,I,Z)
5/18/17	Oklahoma Gas and Electric Company	AR	5.42	9.50	36.38	6/16	Year-end	7.1	(B,*)
5/23/17	Delmarva Power & Light Company	DE	—	9.70	—	12/15	—	31.5	(D,B,I)
5/31/17	Idaho Power Co.	ID	—	9.50	—	—	—	13.3	(B,LIR)
6/1/17	Virginia Electric and Power Company	VA	6.74	9.40	49.49	8/18	—	-12.8	(LIR,10)
6/6/17	Kansas City Power & Light Company	KS	—	—	—	6/14	—	-3.6	(B,11)
6/8/17	Westar Energy, Inc.	KS	—	—	—	9/14	—	16.4	(B,11)
6/16/17	MDU Resources Group, Inc.	ND	7.36	9.65	51.40	12/17	Average	7.5	(B,I)
6/22/17	Kentucky Utilities Company	KY	—	9.70	—	—	—	51.6	(B,R)
6/22/17	Louisville Gas and Electric Company	KY	—	9.70	—	—	—	57.1	(B,R)
6/30/17	Virginia Electric and Power Company	VA	6.74	9.40	49.49	8/18	Average	4.2	(LIR,12)
6/30/17	Virginia Electric and Power Company	VA	7.24	10.40	49.49	8/18	Average	-18.0	(LIR,13)
2017	**2nd quarter: averages/total**		**7.11**	**9.63**	**48.77**			**597.0**	
	Observations		**9**	**14**	**9**			**19**	
7/17/17	Appalachian Power Company	VA	—	—	—	—	—	0.0	(LIR,14)
7/24/17	Potomac Electric Power Company	DC	7.46	9.50	49.14	3/16	Average	36.9	(D)
8/4/17	Maui Electric Company, Limited	HI	—	—	—	—	—	0.0	
8/10/17	Wisconsin Electric Power Company	WI	—	—	—	12/19	—	0.0	(B,Z)
8/10/17	Wisconsin Public Service Corporation	WI	—	—	—	12/19	—	0.0	(B,Z)
8/15/17	Arizona Public Service Company	AZ	7.85	10.00	55.80	12/15	Year-end	362.6	(B)
9/1/17	Virginia Electric and Power Company	VA	6.81	9.40	50.23	8/18	Average	1.0	(LIR,15)
9/22/17	Atlantic City Electric Company	NJ	7.60	9.60	50.47	7/17	Year-end	43.0	(B,D)
9/28/17	Sharyland Utilities, L.P.	TX	—	—	—	—	—	-3.0	(B,D)
9/28/17	Oncor Electric Delivery Company LLC	TX	7.44	9.80	42.50	12/16	Year-end	118.1	(B,D)
2017	**3rd quarter: averages/total**		**7.43**	**9.66**	**49.63**			**558.6**	
	Observations		**5**	**5**	**5**			**10**	
2017	**Year-to-date: averages/total**		**7.09**	**9.74**	**48.50**			**2,171.4**	
	Observations		**29**	**34**	**29**			**52**	

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Amt. ($M)	Footnotes
1/18/17	Missouri Gas Energy	MO	—	—	—	8/16	—	3.2	(LIR,16)
1/18/17	Spire Missouri	MO	—	—	—	8/16	—	4.5	(LIR,16)
1/24/17	Consolidated Edison Co. of NY	NY	6.82	9.00	48.00	12/17	Average	-5.3	(B)
2/9/17	Atmos Energy Corporation	KS	—	—	—		—	0.8	(LIR,17)
2/21/17	Atlanta Gas Light Company	GA	—	10.55	51.00		—	20.4	(B,18)
3/1/17	Washington Gas Light Company	DC	7.57	9.25	55.70	9/15	Average	8.5	
3/17/17	Columbia Gas of Virginia, Inc.	VA	—	—	—	12/15	—	28.5	(B,I)
2017	**1st quarter: averages/total**		**7.20**	**9.60**	**51.57**			**60.6**	
	Observations		**2**	**3**	**3**			**7**	
4/11/17	Southwest Gas Corporation	AZ	7.42	9.50	51.70	11/15	Year-end	16.0	(B)
4/20/17	National Fuel Gas Distribution Corp.	NY	6.92	8.70	42.90	3/18	Average	5.9	
4/26/17	Spire Missouri	MO	—	—	—	2/17	—	3.0	(B,LIR,16)
4/26/17	Missouri Gas Energy	MO	—	—	—	2/17	—	3.0	(B,LIR,16)
4/27/17	Delta Natural Gas Company, Inc.	KY	—	—	—	12/16	Year-end	1.8	(LIR,19)
4/28/17	Intermountain Gas Company	ID	7.30	9.50	50.00	12/16	Average	5.3	
5/11/17	Pacific Gas and Electric Company	CA	—	—	—	12/17	Average	-3.0	(B,Z)
5/23/17	Black Hills Kansas Gas Utility Company	KS	—	—	—	12/16	Year-end	0.6	(LIR)
5/23/17	CenterPoint Energy Resources Corp.	TX	8.02	9.60	55.15	6/16	Year-end	16.5	(B)
6/6/17	Delmarva Power & Light Company	DE	—	9.70	—	12/15	—	4.9	(B,I)
6/22/17	Louisville Gas and Electric Company	KY	—	9.70	—	—	—	6.8	(B,R)
6/28/17	Northern Indiana Public Service Company	IN	—	—	—	12/16	Year-end	11.1	(LIR)
6/30/17	Pivotal Utility Holdings, Inc.	NJ	6.71	9.60	46.00	3/17	Year-end	13.3	(B)
2017	**2nd quarter: averages/total**		**7.27**	**9.47**	**49.15**			**85.2**	
	Observations		**5**	**7**	**5**			**13**	
7/21/17	NorthWestern Corporation	MT	6.96	9.55	46.79	12/15	Average	5.1	(B,)
7/31/17	Consumers Energy Company	MI	5.97	10.10	41.27	12/17	Average	29.2	(I,*)

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas utility decisions (continued)

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Amt. ($M)	Footnotes
8/9/17	Oklahoma Natural Gas Company	OK	—	—	—	12/16	—	0.0	(B,20)
8/10/17	Wisconsin Electric Power Company	WI	—	—	—	12/19	—	0.0	(B,Z)
8/10/17	Wisconsin Gas LLC	WI	—	—	—	12/19	—	0.0	(B,Z)
8/10/17	Wisconsin Public Service Corporation	WI	—	—	—	12/19	—	0.0	(B,Z)
8/21/17	Virginia Natural Gas, Inc.	VA	—	—	—	8/18	Average	2.9	(LIR,21)
8/31/17	UGI Penn Natural Gas, Inc.	PA	—	—	—	9/18	—	11.3	(B)
9/6/17	CenterPoint Energy Resources Corp.	AR	4.58	—	31.02	9/18	Year-end	7.6	(*,B)
9/8/17	Washington Gas Light Company	VA	—	—	—	11/17	—	34.0	(I,B)
9/13/17	Avista Corporation	OR	7.35	9.40	50.00	9/18	Average	3.5	(B,Z)
9/19/17	Columbia Gas of Maryland, Incorporated	MD	7.35	9.70	—	4/17	—	2.4	(B)
9/22/17	ENSTAR Natural Gas Company	AK	8.59	11.88	51.81	12/15	Average	5.8	(I)
9/27/17	South Carolina Electric & Gas Co.	SC	8.15	—	52.16	3/17	Year-end	8.6	(M)
9/27/17	Piedmont Natural Gas Company, Inc.	SC	7.60	10.20	53.00	3/17	Year-end	5.5	(B,22)
2017	**3rd quarter: averages/total**		**7.07**	**10.14**	**46.58**			**115.9**	
	Observations		**8**	**6**	**7**			**15**	
2017	**Year-to-date: averages/total**		**7.15**	**9.75**	**48.43**			**261.8**	
	Observations		**15**	**16**	**15**			**35**	

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

FOOTNOTES

A- Average

B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

CWIP- Construction work in progress

D- Applies to electric delivery only

DCt- Date certain rate base valuation

E- Estimated

F- Return on fair value rate base

Hy- Hypothetical capital structure utilized

I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.

LIR- Limited-issue rider proceeding

M- "Make-whole" rate change based on return on equity or overall return authorized in previous case.

R- Revised

Te- Temporary rates implemented prior to the issuance of final order.

Tr- Applies to transmission service

U- Double leverage capital structure utilized.

YE- Year-end

Z- Rate change implemented in multiple steps.

* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Case withdrawn by company.

(2) Initial proceeding to establish the rates to be charged to customers under the company's transmission, distribution, and storage system improvement charge, or TDSIC, rate adjustment mechanism and reflects investments made between Jan. 1, 2016 and April 30, 2016.

(3) Proceeding determines the revenue requirement for Rider B, which is the mechanism through which the company recovers costs associated with its plan to convert the Altavista, Hopewell and Southampton Power Stations to burn biomass fuels.

(4) Proceeding determines the revenue requirement for Rider GV, which is the mechanism through which the company recovers the costs associated with the new gas fired generation facility, the Greensville County project.

(5) Represents rate decrease associated with the company's Rider R proceeding, which is the mechanism through which the company recovers the investment in the Bear Garden generating facility.

(6) This proceeding determines the revenue requirement for Rider S, which recognizes in rates the company's investment in the Virginia City Hybrid Energy Center.

(7) Increase authorized through a surcharge, Rider W, which reflects in rates investment in the Warren County Power Station.

(8) The commission rejected the company's rate case filing.

(9) Case represents the company's RAC-EE rider, under which it recovers the costs and lost revenues associated with its energy efficiency programs.

(10) Case represents the company's Rider DSM, which involves a consolidation of two riders related to the company's costs and investments in demand-side management and energy conservation programs.

(11) Represents an "abbreviated" rate case.

(12) Case involves Rider US-2, which pertains to the company's investment in three new solar generation facilities with a total capacity of 56 MW.

(13) Case involves Rider BW, which relates to the company's investment in the Brunswick generating plant, which achieved commercial operation on 4/25/16.

(14) Commission rejected the company's request for an accelerated vegetation management program and an associated rate adjustment mechanism.

(15) Case involves Rider U, which pertains to the company's investment in projects to underground certain "at risk" distribution facilities.

(16) Case involves the company's infrastructure system replacement surcharge, or ISRS, rider.

(17) Case involves the company's gas system reliability surcharge, or GSRS, rider.

(18) In this proceeding, the commission adopted an alternative rate plan and authorized the first rate change,

(19) Case involves the company's pipe replacement program, or PRP, rider.

(20) Case involves the company's performance based ratemaking plan.

(21) Case involves the company's Steps to Advance Virginia Energy rider.

(22) Modified "make whole" rate change authorized.