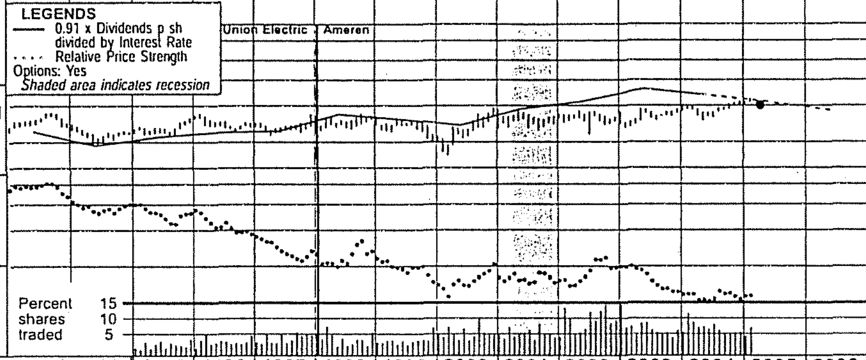
AMEREN NYSE-AEE

RECENT PRICE 48.09 | P/E RATIO 15.4 (Trailing: 17.1 / Median: 13.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 5.3% | VALUE LINE

TIMELINESS 3 Raised 2/18/05
SAFETY 1 Raised 7/17/92
TECHNICAL 4 Lowered 3/25/05
BETA .75 (1.00 = Market)

High:	39.5	42.0	44.1	43.8	44.3	42.9	46.9	46.0	45.3	46.5	50.4	52.0
Low:	30.8	34.6	36.0	34.5	35.6	32.0	27.6	36.5	34.7	37.4	40.6	47.7



Target Price Range
2008 | 2009 | 2010
120
100
80
64
48
32
24
20
16
12
8

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+15%)	8%
Low	45	(-5%)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	3	0	0	1	0	6	5	1	0
to Sell	4	1	1	2	1	8	7	1	0

Institutional Decisions

	2Q2004	3Q2004	4Q2004
to Buy	167	171	177
to Sell	125	113	108
Hld's(000)	105449	101343	103561

% TOT. RETURN 2/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	14.7	9.5
3 yr.	52.6	45.8
5 yr.	132.5	79.6

Ameren was formed on December 31, 1997 through the merger of Union Electric and CIPSCO. Each common share of Union Electric was exchanged for 1.00 share of Ameren, while each common share of CIPSCO was exchanged for 1.03 Ameren shares. Premerger data are for Union Electric only and are not comparable to Ameren data.

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
20.59	22.13	24.24	24.18	25.68	28.10	32.64	24.93	28.20	26.45	34.20	34.45	Revenues per sh	35.30
5.14	5.12	4.96	5.36	5.36	6.11	6.33	5.28	6.29	5.45	5.90	6.40	"Cash Flow" per sh	6.45
2.95	2.86	2.44	2.82	2.81	3.33	3.41	2.66	3.14	2.84	3.00	3.10	Earnings per sh A	3.15
2.46	2.51	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	Div'd Decl'd per sh B ■	2.54
3.05	3.18	2.77	2.37	4.16	6.77	7.99	5.11	4.19	3.65	3.30	3.25	Cap'l Spending per sh	3.15
22.71	23.06	22.00	22.27	22.52	23.30	24.26	24.93	26.73	30.15	31.05	31.75	Book Value per sh C	33.85
102.12	102.12	137.22	137.22	137.22	137.22	138.05	154.10	162.90	195.00	196.00	199.00	Common Shs Outst'g E	208.00
12.6	13.8	15.5	14.2	13.5	11.0	12.1	15.8	13.5	16.2	Bold figures are		Avg Ann'l P/E Ratio	16.0
.84	.86	.89	.74	.77	.72	.62	.86	.77	.86	Value Line		Relative P/E Ratio	1.05
6.6%	6.3%	6.7%	6.3%	6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	estimates		Avg Ann'l Div'd Yield	5.1%
2102.7	2260.4	3326.5	3318.2	3523.6	3855.8	4505.9	3841.0	4593.0	5160.0	6700	6860	Revenues ($mill)	7340
314.1	304.9	347.3	399.1	397.8	469.8	481.0	393.0	517.0	530.7	595	625	Net Profit ($mill)	660
40.0%	39.3%	40.3%	40.1%	39.4%	39.1%	38.4%	38.9%	36.8%	37.0%	37.0%	37.0%	Income Tax Rate	37.0%
4.1%	4.4%	3.7%	3.0%	3.6%	2.9%	4.3%	2.8%	1.9%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
41.0%	41.1%	43.5%	41.0%	42.4%	44.4%	44.2%	46.0%	47.3%	45.0%	46.0%	45.5%	Long-Term Debt Ratio	46.0%
53.9%	53.9%	52.4%	54.8%	53.5%	51.8%	52.2%	51.4%	50.6%	53.0%	52.0%	53.0%	Common Equity Ratio	52.5%
4302.0	4372.6	5760.2	5580.7	5773.4	6176.9	6419.3	7468.0	8606.0	11080	11695	11925	Total Capital ($mill)	13445
5435.4	5382.7	6987.1	6928.0	7165.2	7705.7	8426.6	8914.0	10917	11085	11165	11215	Net Plant ($mill)	11185
8.9%	8.5%	7.5%	8.7%	8.2%	8.9%	8.7%	6.5%	7.4%	6.0%	6.5%	6.5%	Return on Total Cap'l	6.5%
12.4%	11.8%	10.7%	12.1%	12.0%	13.7%	13.4%	9.7%	11.4%	8.5%	9.5%	9.5%	Return on Shr. Equity	9.0%
13.0%	12.4%	11.1%	12.6%	12.5%	14.3%	14.0%	9.9%	11.6%	9.0%	9.5%	9.5%	Return on Com Equity D	9.0%
2.2%	1.5%	.1%	1.2%	1.2%	3.4%	3.6%	.2%	2.2%	1.0%	1.5%	1.5%	Retained to Com Eq	2.0%
84%	88%	99%	90%	91%	77%	75%	98%	81%	90%	85%	82%	All Div'ds to Net Prof	81%

CAPITAL STRUCTURE as of 9/30/04
Total Debt $6458.0 mill. Due in 5 Yrs $1231.0 mill.
LT Debt $6164.0 mill. LT Interest $257.1 mill.
(Incl. debt discount of $7.0 mill.)
(LT interest earned: 4.0x)

Pension Assets-12/03 $1.44 bill. Oblig. $2.09 bill.

Pfd Stock $216.0 mill. Pfd Div'd $11.0 mill.
1,137,595 shs. $3.50 to $7.64 cum. (no par), stated at liquid. value; 191,204 shs., $100 par, 4.50% to to 4.60%; 800,000 shs. 4.00% to 6.625%.

Common Stock 194,796,533 shs.

MARKET CAP: $9.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2001	2002	2003
% Change Retail Sales (KWH)	+4.0	+5.0	+13.8
Avg. Indust. Use (MWH)	2223	2073	2526
Avg. Indust. Revs. per KWH (¢)	4.11	4.11	4.14
Capacity at Peak (Mw)	13296	14500	14804
Peak Load, Summer (Mw)	11505	11710	12860
Annual Load Factor (%)	57.0	59.0	55.0
% Change Customers (yr-end)	+.4	+13.4	+13.3
Fixed Charge Cov. (%)	429	368	361

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '01-'03 to '08-'10
Revenues	3.5%	4.0%	3.0%
"Cash Flow"	2.0%	3.0%	1.0%
Earnings	1.0%	2.5%	.5%
Dividends	1.0%	--	Nil
Book Value	2.0%	2.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	874.0	978.0	1166	823.0	3841.0
2003	1108	1088	1350	1047	4593.0
2004	1216	1152	1317	1475	5160.0
2005	1680	1610	1930	1480	6700
2006	1720	1650	1970	1520	6860

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.42	.80	1.64	d.20	2.66
2003	.52	.68	1.70	.24	3.14
2004	.55	.65	1.20	.42	2.84
2005	.55	.65	1.50	.30	3.00
2006	.57	.68	1.53	.32	3.10

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.635	.635	.635	.635	2.54
2002	.635	.635	.635	.635	2.54
2003	.635	.635	.635	.635	2.54
2004	.635	.635	.635	.635	2.54
2005	.635				

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP Jan.,2003. Supplies elect. and gas to 2,200,000 customers in Missouri (59% elect. revs.) and Illinois (41%). Elect. revs.: resid., 23%; commer., 24%; indust., 23%; other, 30%. Largest indust. customers: primary metals, chemicals, transportation equipment, petroleum refining. 2003 fuels: coal, 85%; nuclear, 13%; other, 2%. Fuel costs, 27% of revenues; labor costs, 12%. 2003 depreciation rate: 3.5%. Estimated plant age: 13 years. Has 7,650 employees, 89,970 stockholders. Chrmn., CEO, and Pres.: Gary L. Rainwater. Inc.: Missouri. Address: 1901 Chouteau Street, St. Louis, Missouri 63166. Telephone: 314-621-3222. Internet: www.ameren.com.

Ameren seeks to move unregulated plants to the rate base. Faced with a shrinking reserve margin and an order by the Missouri regulators to add 700 megawatts of generating capacity, the company filed for authorization to acquire two natural gas-fired peaking units with a capacity of 538 megawatts from its CIPSCO affiliate. It would pay the $258 million book value for the transfer. The exchange is subject to reconsideration of conditions imposed by the commission in its decision approving the arrangement and to sanction by the SEC. The purchase would go a long way towards covering AEE's generating obligations. Without the power, the company would incur heavy expenditures in locating other energy sources. An order on the request is due by midyear.

Management's focus on utility operations suggests steady but unexciting earnings growth for the next several years. Since the late Nineties, when many utilities were investing in enterprises unrelated to their basic operations, often without success, Ameren stuck to its core business of generating and selling electricity. During this period, the company bought three neighboring Illinois utilities. All three acquisitions are contributing to net. But because growth in Ameren's jurisdiction is slow, we look for only modest profit gains through 2008-2010.

Despite last year's issuance of 32 million common shares, earnings should rise in 2005. The company will benefit from a full year of higher gas rates, the end of the electric rate reduction in Missouri on April 1st, and higher retail energy sales. A return to normal summer weather would be another plus. (Mild temperatures in the 2004 September quarter were a drag on sales.) A planned outage of the Callaway nuclear plant for the repair of steam generators will pare these gains somewhat. All told, we estimate a 6% increase in 2005 earnings, to $3.00 a share. Lower payroll expense should help lift results next year.

The yield is a full percentage point above the industry norm. But a high payout ratio points to no dividend hike for the next 3 to 5 years. On balance, we rate this financially strong company an average utility selection.

Arthur H. Medalie — *April 1, 2005*

(A) EPS basic. Excl. nonrecur. gain: '03, 11¢. Next egs. report due late Apr. '04 egs. don't add due to change in no. of shs.
(B) Div'ds historically paid in late March, late June, late Sept., and late Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred chgs. in '03, $8.00/sh. (D) Rate base: orig. cost depreciated. Rate allowed in MO on common equity in '96: 14.0%; earned on average com. eq. in '03: 12.3%. Regul. Clim.: Average. (E) In millions.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	80

DTE ENERGY CO. NYSE-DTE

RECENT PRICE 44.40 | P/E RATIO 15.6 (Trailing: 17.6 Median: 11.0) | RELATIVE P/E RATIO 0.84 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 4 Raised 4/9/04
SAFETY 3 Lowered 10/5/01
TECHNICAL 3 Raised 1/28/05
BETA .70 (1.00 = Market)

High:	30.3	34.9	37.3	34.8	49.3	44.7	41.3	47.1	47.7	49.5	45.5	47.0
Low:	24.3	25.8	27.6	26.1	33.4	31.1	28.4	33.1	33.1	34.0	37.9	42.4

2008-10 PROJECTIONS

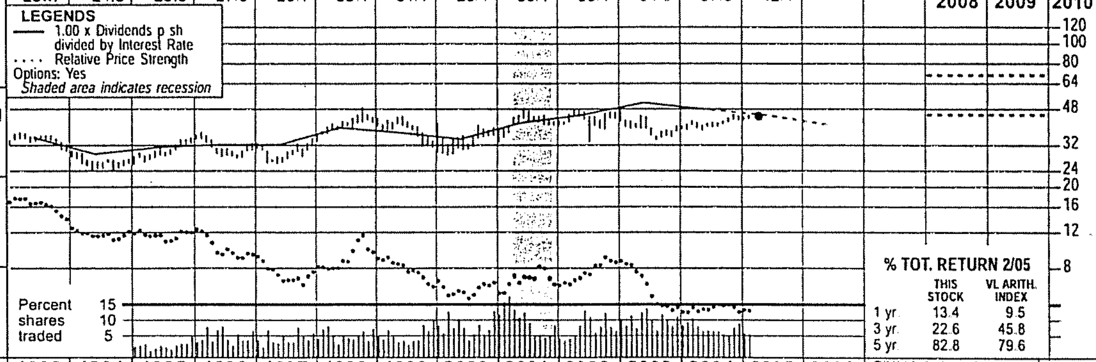
	Price	Gain	Ann'l Total Return
High	70	(+60%)	16%
Low	45	(Nil)	5%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	5	0
to Sell	0	0	0	1	0	0	0	7	0

Institutional Decisions

	2Q2004	3Q2004	4Q2004
to Buy	120	133	146
to Sell	136	119	112
Hld's(000)	105738	92459	96642



% TOT. RETURN 2/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.4	9.5
3 yr.	22.6	45.8
5 yr.	82.8	79.6

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
21.81	22.51	24.44	24.20	24.18	24.29	25.05	25.12	25.94	29.10	32.60	39.24	48.71	40.30	41.76	44.60	*44.60*	*48.85*	Revenues per sh	*58.50*
5.13	6.03	6.45	6.67	6.43	6.52	7.07	7.10	7.42	7.61	8.40	8.59	6.98	8.31	6.95	6.81	*7.75*	*8.50*	"Cash Flow" per sh	*10.75*
2.65	3.26	3.64	3.79	3.34	2.67	3.02	2.80	2.88	3.05	3.33	3.27	2.15	3.83	2.85	2.55	*3.30*	*3.70*	Earnings per sh A	*4.75*
1.68	1.78	1.88	1.98	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	*2.06*	*2.06*	Div'd Decl'd per sh B ■	*2.10*
1.65	1.57	1.85	2.83	2.71	2.61	3.13	3.66	3.14	3.83	5.10	5.25	6.80	5.88	4.45	5.40	*5.95*	*5.80*	Cap'l Spending per sh	*7.00*
16.14	17.62	19.37	21.18	22.41	22.96	23.68	23.73	24.55	25.49	26.95	28.15	28.48	27.26	31.36	31.85	*33.20*	*34.50*	Book Value per sh C	*40.75*
146.86	146.92	146.98	147.02	147.05	144.86	145.12	145.12	145.10	145.07	145.04	142.65	161.13	167.46	168.61	174.21	*176.00*	*172.00*	Common Shs Outst'g D	*164.00*
7.9	8.2	8.3	8.5	10.2	10.0	10.0	11.2	10.3	13.3	11.6	10.3	19.3	11.3	13.7	16.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*12.0*
.60	.61	.53	.52	.60	.66	.67	.70	.59	.69	.66	.67	.99	.62	.78	.85	*estimates*		Relative P/E Ratio	*.80*
8.0%	6.6%	6.2%	6.1%	6.0%	7.7%	6.9%	6.6%	6.9%	5.1%	5.3%	6.1%	5.0%	4.8%	5.3%	5.0%			Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/04
Total Debt $8619.0 mill. Due in 5 Yrs $2956.0 mill.
LT Debt $7627.0 mill. LT Interest $488.0 mill.
Incl. $70.0 mill. capitalized leases, $289.0 mill. Trust Preferred Securities, $179.0 equity-linked debt securities, & $1.4 bill. securitized bonds.
(LT interest earned: 2.1x)
Leases, Uncapitalized Annual rentals $72.0 mill.

Pension Assets-12/03 $2.35 bill. Oblig. $2.75 bill.
Pfd Stock None
Common Stock 174,209,034 shs. as of 12/31/04
MARKET CAP: $7.7 billion (Large Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
3635.5	3645.4	3764.0	4221.0	4728.0	5597.0	7849.0	6749.0	7041.0	7114.0	*7850*	*8400*	Revenues ($mill)	*9600*
465.7	422.3	429.0	449.0	483.0	468.0	329.0	632.0	480.0	443.0	*580*	*645*	Net Profit ($mill)	*790*
38.6%	39.3%	37.5%	25.5%	11.0%	1.9%	--	--	--	41.7%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
.8%	1.3%	.5%	.9%	.8%	.6%	.9%	4.9%	1.3%	.7%	*4.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
50.8%	52.1%	51.4%	53.9%	50.9%	50.3%	63.3%	63.0%	59.2%	57.2%	*54.0%*	*53.0%*	Long-Term Debt Ratio	*49.5%*
44.9%	46.0%	46.7%	46.1%	49.1%	49.7%	36.7%	37.0%	40.8%	42.8%	*46.0%*	*47.0%*	Common Equity Ratio	*50.5%*
7647.4	7483.3	7620.0	8021.0	7961.0	8077.0	12517	12350	12956	12976	*12625*	*12675*	Total Capital ($mill)	*13300*
8801.1	8760.9	8934.0	6943.0	7148.0	7387.0	9543.0	9813.0	10324	10491	*10750*	*10950*	Net Plant ($mill)	*11500*
7.9%	7.5%	7.4%	7.4%	7.9%	7.5%	4.4%	7.3%	5.6%	5.0%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
12.4%	11.8%	11.6%	12.1%	12.4%	11.7%	7.2%	13.8%	9.1%	8.0%	*10.0%*	*11.0%*	Return on Shr. Equity	*12.0%*
12.7%	11.8%	11.7%	12.0%	12.4%	11.7%	7.2%	13.8%	9.1%	8.0%	*10.0%*	*11.0%*	Return on Com Equity E	*12.0%*
4.1%	3.1%	3.3%	3.9%	4.7%	4.3%	.1%	6.4%	2.5%	1.6%	*4.0%*	*5.0%*	Retained to Com Eq	*6.5%*
70%	75%	72%	68%	62%	63%	99%	53%	72%	80%	*62%*	*56%*	All Div'ds to Net Prof	*44%*

ELECTRIC OPERATING STATISTICS

	2001	2002	2003
% Change Retail Sales (KWH)	-4.1	+5.0	-1.7
Avg. Indust. Use (MWH)	14429	13589	12254
Avg. Indust. Revs. per KWH (¢)	5.36	5.15	5.16
Capacity at Peak (Mw)	11053	11060	11043
Peak Load, Summer (Mw)	11860	11308	10470
Annual Load Factor (%)	51.4	55.1	52.9
% Change Customers (yr-end)	+.7	+.5	-.2
Fixed Charge Cov. (%)	148	193	135

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '01-'03 to '08-'10
Revenues	6.0%	10.5%	4.5%
"Cash Flow"	1.5%	--	5.5%
Earnings	-2.0%	--	7.0%
Dividends	.5%	--	.5%
Book Value	3.5%	3.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1896	1478	1636	1739	6749.0
2003	2095	1600	1654	1692	7041.0
2004	2093	1501	1594	1926	7114.0
2005	*2250*	*1700*	*1750*	*2150*	*7850*
2006	*2500*	*1800*	*1850*	*2250*	*8400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.24	.42	.96	1.21	3.83
2003	.64	d.22	1.06	1.37	2.85
2004	1.13	.20	.54	.65	2.55
2005	*1.15*	*.45*	*.60*	*1.10*	*3.30*
2006	*1.35*	*.50*	*.65*	*1.20*	*3.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.515	.515	.515	.515	2.06
2002	.515	.515	.515	.515	2.06
2003	.515	.515	.515	.515	2.06
2004	.515	.515	.515	.515	2.06
2005	.515				

BUSINESS: DTE Energy Company is a holding company for The Detroit Edison Company, which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and Michigan Consolidated Gas (MichCon). Customers: 2.1 mill. electric, 1.3 mill. gas. Acq'd MCN Energy 6/01. Has various nonutility operations. Electric rev. breakdown, '03: residential, 39%; comm'l, 38%; ind'l, 18%; other, 5%. Generating sources, '03: coal, 71%; nuclear, 16%; other, 1%; purch., 12%. Fuel costs: 32% of revs. '03 reported depr. rates: 3.4% elec., 3.5% gas. Has 11,100 employees, 105,000 com. stockholders. Chairman & CEO: Anthony F. Earley, Jr. President: Gerard M. Anderson. Inc.: MI. Address: 2000 Second Ave., Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's utility subsidiaries have some regulatory matters pending. Detroit Edison (which received a base rate increase of $373.7 million last fall) has put forth a revenue-neutral filing to adjust its tariff structure so that commercial and industrial users (which have been subsidizing small customers) pay lower rates. This would benefit the utility because it would reduce the incentive for large customers to switch to an alternative power supplier. DE has already lost roughly 16% of its load to competitive suppliers. A ruling from the Michigan Public Service Commission (MPSC) should come by year-end. The utility is also asking the MPSC for an accounting order that would allow it to capitalize the cost of an enterprise software system it is installing. If DE doesn't get the order, pretax income would be lowered by $30 million-$40 million this year. Finally, MichCon still awaits a decision on its request for a gas rate hike of $194 million based on an 11.5% return on equity. An administrative law judge and the MPSC's staff have recommended increases of $60 million and $76 million, respectively. An order should come soon.

Earnings should advance considerably this year, followed by improvement in 2006. Rate relief and increased income from nonregulated activities should help. Our 2005 estimate is at the low end of DTE's target of $3.30-$3.60 a share. Next year, MichCon's rate increase will be in place for the seasonally strong first quarter, and residential customers' electric tariffs will rise because a rate cap for them expires at the end of 2005.

DTE will begin executing its cash redeployment strategy this year. From 2005-2008, the company expects to have $1.65 billion to use to reduce debt, invest in nonutility operations, or buy back stock. The board of directors has authorized the repurchase of up to $700 million of common stock through 2008.

This untimely stock offers an attractive yield. Although little or no dividend growth is likely through 2008-2010 (because much of the aforementioned cash flow arises from DTE's synthetic fuels investments, which will roll off by late decade), total-return potential over that time is above average, by utility standards.

Paul E. Debbas, CFA *April 1, 2005*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '95, (22¢); '96, (67¢); '01, 2¢; '03, (16¢); gain (loss) on discont. ops.: '03, 40¢; '04, (6¢). '03 EPS don't add due to rounding, '04 due to change in shares. Next earnings report due late April. (B) Div'ds historically paid in mid-Jan., April, July, and Oct. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '03: $33.55/sh. (D) In mill. (E) Rate base: Net orig cost. Rate allowed on com. eq. (elec.) in '04: 11%; gas: 11.6%; earned on avg. com. eq., '03: 9.7%. Regulat. Climate: Below Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	55

EXELON CORP. NYSE-EXC

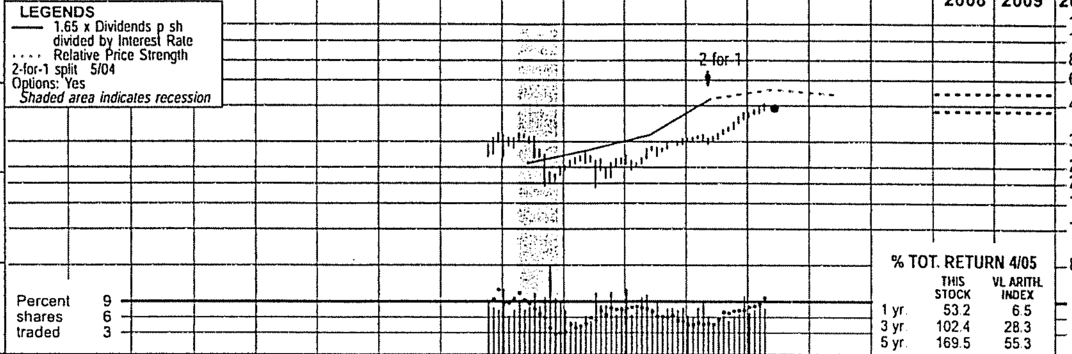
RECENT PRICE 46.67 | P/E RATIO 15.3 (Trailing: 15.9 Median: NMF) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Raised 8/6/04
SAFETY 1 Raised 6/3/05
TECHNICAL 3 Lowered 5/6/05
BETA .75 (1.00 = Market)

	2000	2001	2002	2003	2004	2005
High:	35.5	35.1	28.5	33.3	44.9	49.7
Low:	26.9	19.4	18.9	23.0	30.9	41.8

Target Price Range 2008 | 2009 | 2010

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



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+20%)	7%
Low	45	(-5%)	3%

Insider Decisions

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

Institutional Decisions

	2Q2004	3Q2004	4Q2004
to Buy	222	260	291
to Sell	219	206	205
Hld's(000)	415041	415458	428110

% TOT. RETURN 4/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	53.2	6.5
3 yr.	102.4	28.3
5 yr.	169.5	55.3

Exelon Corp. was formed on October 20, 2000 upon a merger of equals between PECO Energy Co. and Unicom Corp. (Unicom was the holding company for Commonwealth Edison Co.) PECO Energy stockholders received one common share in Exelon for each common share held. Unicom investors exchanged each of their common shares for .875 of an Exelon share and $3.00 in cash. Exelon declared an initial annual common dividend of $0.85 a share (adjusted for May 5, 2004 stock split).

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
--	--	--	--	19.40	11.75	23.58	23.13	23.89	21.85	21.80	22.05	Revenues per sh	23.60
--	--	--	--	3.55	1.84	5.06	5.03	5.02	5.68	6.05	6.30	"Cash Flow" per sh	7.15
--	--	--	--	1.86	1.39	2.20	2.40	2.44	2.75	3.05	3.20	Earnings per sh A	3.65
--	--	--	--	--	--	.91	.88	.96	1.26	1.60	1.68	Div'd Decl'd per sh B ▪	1.92
--	--	--	--	--	1.18	3.18	3.33	2.95	2.89	2.85	2.80	Cap'l Spending per sh	2.70
--	--	--	--	--	11.31	12.82	11.97	12.84	14.19	15.60	17.40	Book Value per sh C	23.05
--	--	--	--	630.20	638.01	642.01	646.63	662.00	664.20	670.0	680.00	Common Shs Outst'g D	710.00
--	--	--	--	--	22.4	13.2	10.5	11.8	13.0	Bold figures are		Avg Ann'l P/E Ratio	14.0
--	--	--	--	--	1.46	.68	.57	.67	.69	Value Line		Relative P/E Ratio	.95
--	--	--	--	--	--	3.1%	3.5%	3.4%	3.5%	estimates		Avg Ann'l Div'd Yield	3.8%
--	--	--	--	12225	7499.0	15140	14955	15812	14515	14600	15000	Revenues ($mill)	16750
--	--	--	--	1233.0	590.0	1465.0	1599.0	1641.0	1844.0	2050	2195	Net Profit ($mill)	2615
--	--	--	--	35.5%	36.6%	38.9%	36.7%	32.9%	27.5%	30.0%	32.0%	Income Tax Rate	35.0%
--	--	--	--	--	.5%	1.2%	1.2%	.9%	1.0%	.5%	.5%	AFUDC % to Net Profit	.5%
--	--	--	--	35.5%	62.3%	59.3%	61.2%	61.1%	56.1%	55.0%	51.5%	Long-Term Debt Ratio	43.0%
--	--	--	--	10.1%	34.7%	37.9%	36.1%	38.5%	43.5%	44.5%	48.0%	Common Equity Ratio	56.5%
--	--	--	--	--	20803	21719	21464	22079	21658	23550	24675	Total Capital ($mill)	28950
--	--	--	--	--	12936	13742	17134	20630	21482	22900	24325	Net Plant ($mill)	28600
--	--	--	--	--	4.1%	9.0%	9.4%	9.2%	10.4%	10.5%	10.5%	Return on Total Cap'l	10.5%
--	--	--	--	--	7.5%	16.6%	19.2%	19.1%	19.4%	19.5%	18.5%	Return on Shr. Equity	16.0%
--	--	--	--	--	7.8%	17.2%	20.1%	18.8%	19.5%	19.5%	18.5%	Return on Com Equity E	16.0%
--	--	--	--	--	7.8%	10.1%	12.8%	11.5%	10.7%	9.0%	8.5%	Retained to Com Eq	7.5%
--	--	--	--	--	4%	43%	38%	40%	45%	53%	53%	All Div'ds to Net Prof	53%

CAPITAL STRUCTURE as of 3/31/05

Total Debt $14,334 mill. Due in 5 Yrs $7,435 mill.
LT Debt $10,997 mill. LT Interest $690 mill.
Includes $4,311 mill. nonrecourse transition bonds.
(LT interest earned: 4.9x)

Pension Assets-12/04 $9.8 bill. Oblig. $7.0 bill.
Pfd Stock $87.0 mill. Pfd Div'd $4.0 mill.
Includes $87.0 mill. in preferred securitites of subsidiaries.

Common Stock 668,505,172 shs.

MARKET CAP: $31.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2002	2003	2004
% Change Retail Sales (KWH)	+3.3	-1.0	+2.5
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)	40764	N/A	34687
Peak Load (Mw)	N/A	N/A	22060
Nuclear Capacity Factor (%)	92.7	93.4	93.5
% Change Customers (yr-end)	N/A	N/A	N/A
Fixed Charge Cov. (%)	307	323	377

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	--	3.5%	.5%
"Cash Flow"	--	8.0%	5.5%
Earnings	--	6.5%	6.5%
Dividends	--	--	11.0%
Book Value	--	--	10.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2002	3357	3519	4370	3709	14955
2003	4074	3721	4441	3576	15812
2004	3722	3550	3865	3378	14515
2005	3561	3550	4000	3489	14600
2006	3700	3650	4100	3550	15000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2002	.37	.57	.85	.61	2.40
2003	.61	.62	.73	.48	2.44
2004	.56	.78	.86	.55	2.75
2005	.75	.67	1.00	.63	3.05
2006	.80	.71	1.03	.66	3.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ▪ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.22	.22	.22	.22	.88
2003	.23	.23	.25	.25	.96
2004	.275	.275	.305	.40	1.26
2005	.40	.40			

BUSINESS: Exelon Corp. is the holding company of PECO Energy and Commonwealth Edison (a former unit of Unicom). Serves 5.2 million electricity and 460,000 gas distribution customers in Illinois and Pennsylvania, and markets energy in the mid-Atlantic and Midwest regions. 2004 distrib. rev. breakdown: resid'l, 47.0%; small comm'l & ind'l, 30.6%; large comm'l & ind'l, 18.2%; other, 4.2%. '04 pwr. supply: nuclear, 48%; purch. pwr, 25%; fossil & hydro, 26%; other, 1%. Operates nonregulated energy (trading and delivery) and utility related services. 2004 deprec. rate 6.7%. Has 17,300 employees; 100,000 stkhldrs. Chrmn, CEO & Pres.: John W. Rowe. Inc.: PA. Addr.: 10 South Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-2345. Web: www.exeloncorp.com.

Exelon is working to smooth the approval process of its pending acquisition of Public Service Enterprise Group (PSEG). The company announced an agreement last December 20th, and hopes to close the deal by the second quarter of 2006. Among the various federal and state agencies reviewing the transaction, the New Jersey Board of Public Utilities (NJBPU) and the Federal Energy Regulatory Commission (FERC) stand out. In view of the size of the combined company and concerns voiced by competitors, industrial customers, and consumer groups over market power, the NJBPU appears inclined to undertake a close examination of the deal. Too, the FERC could well decide to hold extensive hearings. Exelon and PSEG have proposed to expand capacity divestitures (from 5,500 megawatts to 6,600 Mws) to ease these concerns. Management is seeking settlements of major issues with key intervenors to speed the process. In a best case scenario, the deal would be finalized at the end of the March, 2006 quarter. If the FERC decides to hold hearings, the process could drag on beyond mid-2006, posing some risk to closure.

Exelon Electric & Gas would be a big player in the Midwest and Pennsylvania-New Jersey-Maryland power regions. This combined Exelon/PSEG entity would control 52,000 Mws of capacity and produce some $27 billion in revenues and over $3 billion in net profit. Management expects considerable cost savings from improved operating efficiencies at PSEG's nuclear plants, among other actions, which should support strong margins and help to contain electricity rates. The company would have a solid traditional energy delivery division and a growing, profitable, competitive energy business. Exelon Electric & Gas ought to post better 3- to 5-year earnings and dividend advances than Exelon and PSEG would on their own. Exelon plans to issue $12.2 billion worth of common stock in the deal, and assume $14.0 billion in PSEG debt.

Top-quality Exelon stock has posted steady share-price gains over the past two years. Despite the high valuation, the equity still offers conservative investors worthwhile total returns to 2008-2010, versus the utility industry average.

David M. Reimer *June 3, 2005*

(A) Diluted earnings. Excludes nonrecurring items: '01, 2¢; '02, d18¢; '03, d$1.06; 1Q,'04, 4¢; 3Q, '04, d1¢. Next earnings report due late July. (B) Dividends historically paid in early Mar., June, Sep., and Dec. ▪ Div'd. reinvestment program available. (C) Includes deferred charges in '04, $15.13/sh. (D) In millions, adjusted for split. (E) Rate base: N/A. Regulatory Climate: Average. Earned on '04 average common equity: 20.5%. (F) 2000 data reflect PECO Energy and the addition of Unicom from Oct. 20th.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	85

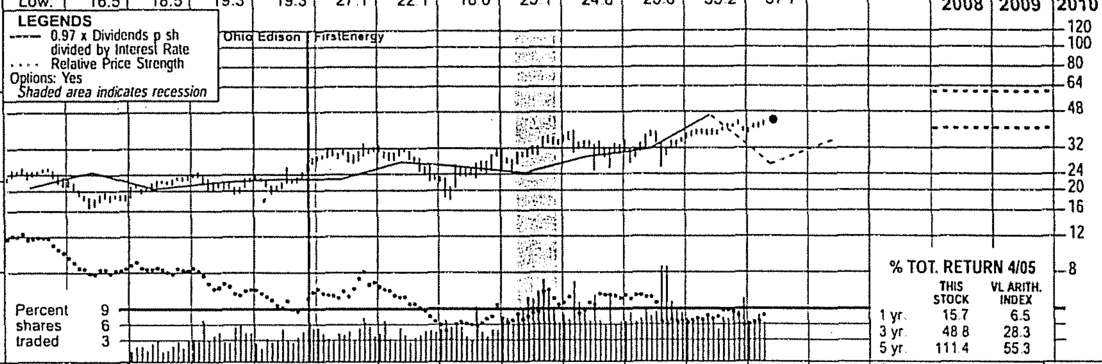
FIRSTENERGY NYSE-FE

RECENT PRICE 43.79 | P/E RATIO 15.4 (Trailing: 16.5 Median: 12.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 4 Raised 5/14/04
SAFETY 3 Raised 10/16/92
TECHNICAL 4 Lowered 5/20/05
BETA .75 (1.00 = Market)

High:	22.8	23.8	24.9	29.0	34.1	33.2	32.1	37.0	39.1	38.9	43.4	44.5
Low:	16.5	18.5	19.3	19.3	27.1	22.1	18.0	25.1	24.8	25.8	35.2	37.7

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



Target Price Range
2008 | 2009 | 2010

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+35%)	11%
Low	40	(-10%)	2%

Insider Decisions

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

Institutional Decisions

	2Q2004	3Q2004	4Q2004
to Buy	137	150	162
to Sell	159	141	133
Hld's(000)	225354	227738	227203

% TOT. RETURN 4/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	15.7	6.5
3 yr.	48.8	28.3
5 yr.	111.4	55.3

FirstEnergy was formed through the affiliation of Ohio Edison Company and Centerior Energy in November of 1997. Ohio Edison stockholders received one share of FirstEnergy for every Ohio Edison share, and Centerior stockholders received .52 of a FirstEnergy share for each Centerior share. In November of 2001, FirstEnergy acquired GPU. GPU holders received $40 in cash or stock for each GPU share. Data prior to 1998 reflect Ohio Edison on a stand-alone basis and are not comparable with FirstEnergy data.

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
16.16	16.19	12.26	24.72	27.19	31.31	26.88	40.83	37.31	37.76	*35.60*	*37.00*	Revenues per sh	*41.00*
4.07	4.83	3.66	5.33	6.89	7.28	5.48	6.45	4.79	7.60	*7.90*	*7.15*	"Cash Flow" per sh	*7.00*
2.05	2.10	1.94	1.95	2.50	2.69	2.84	2.54	1.47	2.77	*2.85*	*3.45*	Earnings per sh A	*4.00*
1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.91	*1.24*	*1.72*	Div'd Decl'd per sh B ■	*2.00*
1.30	.97	.89	2.75	2.69	2.74	2.86	3.35	2.60	2.57	*3.30*	*3.60*	Cap'l Spending per sh	*3.00*
15.78	16.41	18.07	18.77	19.63	20.72	24.86	23.92	25.13	26.04	*27.65*	*29.35*	Book Value per sh C	*35.00*
152.57	152.57	230.21	237.07	232.45	224.53	297.64	297.64	329.84	329.84	*329.84*	*329.84*	Common Shs Outst'g D	*329.84*
10.5	10.4	11.8	15.4	11.3	9.2	10.9	13.0	22.5	14.1	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.70	.65	.68	.80	.64	.60	.56	.71	1.28	.75	*Value Line*		Relative P/E Ratio	*.85*
7.0%	6.9%	6.6%	5.0%	5.3%	6.1%	4.8%	4.6%	4.5%	4.9%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*
2465.9	2469.8	2821.4	5861.3	6319.6	7029.0	7999.4	12152	12307	12453	*11750*	*12200*	Revenues ($mill)	*13500*
324.5	330.6	333.6	507.2	644.8	661.7	727.0	827.6	490.8	932.6	*960*	*1160*	Net Profit ($mill)	*1360*
38.1%	37.8%	38.4%	38.8%	38.0%	36.3%	39.5%	41.5%	43.9%	42.2%	*41.0%*	*41.0%*	Income Tax Rate	*41.0%*
1.7%	.9%	1.0%	1.5%	2.1%	4.1%	4.9%	3.0%	6.5%	2.7%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.1%	48.6%	57.5%	54.0%	52.3%	52.3%	60.1%	60.2%	53.1%	52.8%	*49.0%*	*48.5%*	Long-Term Debt Ratio	*43.5%*
43.3%	44.8%	34.3%	37.8%	39.8%	41.5%	37.2%	38.0%	45.0%	45.4%	*49.5%*	*49.5%*	Common Equity Ratio	*55.0%*
5566.0	5583.0	12124	11756	11470	11205	19907	18756	18414	18938	*18500*	*19525*	Total Capital ($mill)	*21000*
5695.5	5417.9	9573.2	9242.6	9093.3	7575.1	12428	12680	13269	13478	*13725*	*14100*	Net Plant ($mill)	*14700*
8.0%	7.8%	3.8%	6.4%	7.8%	7.9%	4.9%	6.3%	4.6%	6.5%	*6.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
11.7%	11.5%	6.5%	9.4%	11.8%	12.4%	9.2%	11.1%	5.7%	10.4%	*10.0%*	*11.5%*	Return on Shr. Equity	*11.5%*
12.2%	12.1%	7.4%	9.9%	12.5%	12.9%	8.9%	10.5%	5.4%	10.6%	*10.5%*	*11.5%*	Return on Com Equity E	*11.5%*
3.2%	3.4%	1.6%	2.3%	5.0%	5.7%	4.3%	4.3%	NMF	4.9%	*6.0%*	*6.0%*	Retained to Com Eq	*6.0%*
76%	75%	80%	80%	65%	60%	56%	63%	101%	55%	*45%*	*51%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 3/31/05
Total Debt $10879 mill. **Due in 5 Yrs** $3793.3 mill.
LT Debt $9608.7 mill. **LT Interest** $576.5 mill.
Incl. $284.8 mill. 9% ($25 par) cumulative mandatorily redeemable preferred securities.
(LT interest earned: 3.7x)
Leases, Uncapitalized Annual rentals $183.0 mill.
Pension Assets-12/04 $3.97 bill. **Oblig.** $4.36 bill.
Pfd Stock $349.9 mill. **Pfd Div'd** $26.2 mill.
Common Stock 329,836,276 shs. **as of 5/2/05**
MARKET CAP: $14 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2002	2003	2004
% Change Retail Sales (KWH)	-.4	-1.5	-.6
Avg. Indust. Use (MWH)	NMF	NMF	NMF
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 (%)	60.5	64.7	66.7
% Change Customers (yr-end)	+1.0	+.5	+1.1
Fixed Charge Cov. (%)	217	186	316

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	9.5%	12.5%	*1.0%*
"Cash Flow"	5.5%	3.5%	*2.0%*
Earnings	2.0%	1.0%	*10.0%*
Dividends	1.0%	2.0%	*3.5%*
Book Value	5.0%	6.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	2762	2898	3451	3040	12152
2003	3221	2853	3434	2799	12307
2004	3027	3041	3435	2950	12453
2005	2812	*2850*	*3238*	*2850*	*11750*
2006	*2950*	*2950*	*3350*	*2950*	*12200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.38	.79	1.05	.32	2.54
2003	.37	.07	.78	.25	1.47
2004	.53	.62	.91	.71	2.77
2005	.42	*.71*	*1.01*	*.71*	*2.85*
2006	*.55*	*.85*	*1.20*	*.85*	*3.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.375	.375	.375	.375	1.50
2002	.375	.375	.375	.375	1.50
2003	.375	.375	.375	.375	1.50
2004	.375	.375	.375	.375	1.50
2005	.413	.413			

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, and Jersey Central Power & Light. Provides electric service to 4.4 million customers in Ohio (58% of revenues), New Jersey (22%) and Pennsylvania (20%). Electric revenue breakdown by customer class and generating sources not provided by company. Fuel costs: 36% of revenues. '04 reported depreciation rates: 2.1%-2.8%. Has 15,200 employees, 153,000 common stockholders. Chairman: George M. Smart. President & CEO: Anthony J. Alexander. COO: Richard R. Grigg. Inc.: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 330-384-5100. Internet: www.firstenergycorp.com.

FirstEnergy's earnings should improve just modestly in 2005, but they should rise sharply in 2006. This year, Jersey Central Power & Light (JCP&L) should benefit from rate relief. Our $2.85-a-share estimate is at the top end of the company's target of $2.70-$2.85. In 2006, transition-cost amortization will decline sharply, thereby benefiting earnings, but we estimate that "cash flow" will decline due to a credit (intended to encourage customer choice) on customers' bills. Even so, "cash flow" should amply exceed the sum of capital spending and dividends.

Some regulatory matters are pending. FirstEnergy has asked the Ohio regulators for recovery of fuel costs that have risen sharply since 2002. Separately, the Ohio commission has allowed the company to defer $24 million of transmission costs for future recovery, which FirstEnergy will seek beginning next year. The company also wants to defer these costs (an estimated $80 million-$100 million this year) in Pennsylvania. JCP&L has settled with the staff of the New Jersey Board of Public Utilities (subject to BPU approval) for a $51.1 million (2.4%) rate hike based on a 9.75% return on equity. The utility had filed for $56 million. But JCP&L won't recoup any of the $153 million of power costs that was disallowed in 2003.

We have raised the company's Financial Strength rating from B+ to B++. FirstEnergy has been using its strong cash flow to reduce debt. This helped the fixed-charge coverage improve considerably in 2004. The common-equity ratio is very healthy, too.

The dividend was boosted in 2004, and FirstEnergy might repurchase stock. The company intends to raise the dividend by 4%-5% annually and maintain a payout ratio of 50%-60%. We haven't factored a stock buyback into our estimates and projections because the board hasn't authorized one, but this is under consideration.

The yield of this untimely stock is only average by utility standards, though 3- to 5-year total-return potential is a cut above average. Investors should be aware of an ongoing SEC investigation of the company's disclosure of problems with the Davis-Besse nuclear plant and an earnings restatement in 2003.

Paul E. Debbas, CFA — *June 3, 2005*

(A) Diluted EPS. Excl. nonrec. losses: '02, 40¢; '03, 25¢; '04, 11¢; gains (loss) from disc. ops.: '03, (33¢); '04, 1¢; '05, 6¢. '04 EPS don't add due to rounding. Next egs. report due late July. (B) Div'ds historically paid early Mar., June, Sept., & Dec. Five div'ds decl. in '04, 3 expected in '05. ■ Div'd reinv. plan avail. † Shareholder invest. plan avail. (C) Incl. intang.: In '04: $37.30/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate all'd on com. eq. in NJ in '03: 9.5%; earned on avg. com. eq., '04: 10.8%. Regul. Clim.: OH, Above Avg.; PA, NJ, Avg.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	60
Earnings Predictability	60

MGE ENERGY INC. NDQ-MGEE

RECENT PRICE	P/E RATIO	(Trailing / Median)	RELATIVE P/E RATIO	DIV'D YLD
34.10	18.5	Trailing: 19.3; Median: 15.0	.99	4.0%

VALUE LINE

TIMELINESS **5** Lowered 11/19/04

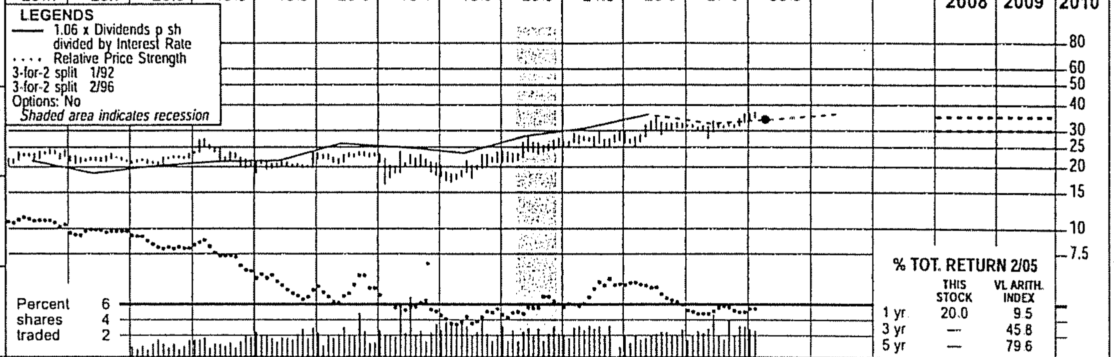
SAFETY **1** New 1/3/03

TECHNICAL **3** Raised 3/18/05

BETA .60 (1.00 = Market)

High:	23.3	23.3	27.5	23.8	23.8	23.9	23.7	27.8	30.1	35.8	36.4	37.2
Low:	20.7	20.3	19.6	18.5	20.6	16.4	16.8	20.9	24.6	25.0	27.6	33.3

Target Price Range 2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+5%)	5%
Low	30	(-10%)	1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	4	1	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2004	3Q2004	4Q2004
to Buy	31	28	42
to Sell	27	19	15
Hld's(000)	4291	4450	4750

% TOT. RETURN 2/05

	THIS STOCK	VL ARITH. INDEX
1 yr	20.0	9.5
3 yr	—	45.8
5 yr	—	79.6

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
13.93	13.77	14.47	14.21	15.18	15.23	15.46	15.75	16.46	15.53	16.96	19.50	19.55	19.75	21.89	20.84	*21.30*	*22.05*	Revenues per sh	*23.30*
2.94	2.96	2.83	2.79	2.86	2.92	3.03	2.41	3.26	3.59	3.81	3.89	3.78	3.33	2.94	2.88	*3.10*	*3.25*	"Cash Flow" per sh	*4.00*
1.30	1.36	1.52	1.45	1.51	1.53	1.49	.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	*1.90*	*2.00*	Earnings per sh A	*2.45*
1.12	1.15	1.17	1.19	1.19	1.25	1.26	1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	*1.37*	*1.38*	Div'd Decl'd per sh B ■	*1.44*
1.98	1.43	1.24	.77	1.47	1.64	1.19	1.36	1.35	1.92	3.16	4.44	2.47	4.45	4.52	*4.70*	*4.55*	*4.00*	Cap'l Spending per sh	*2.25*
10.30	10.62	10.98	11.24	11.51	11.78	12.01	11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	*15.45*	*17.40*	Book Value per sh C	*18.85*
15.62	16.02	16.05	16.05	16.08	16.08	16.08	16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	*20.40*	*20.40*	Common Shs Outst'g D	*20.40*
11.8	10.8	11.3	14.3	15.2	14.3	14.5	28.1	14.5	16.2	14.0	11.7	14.8	16.0	17.5	18.0	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.89	.80	.72	.87	.90	.94	.97	1.76	.84	.84	.80	.76	.76	.87	1.00	.95	*Value Line*		Relative P/E Ratio	*.95*
7.3%	7.8%	6.8%	5.7%	5.2%	5.7%	5.8%	5.5%	6.3%	5.8%	6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*
						248.6	253.3	264.7	249.8	274.0	324.1	333.7	347.1	401.5	424.9	*435*	*450*	Revenues ($mill)	*475*
						24.0	13.2	22.5	22.2	23.8	27.4	27.2	29.2	30.6	33.8	*36.0*	*38.0*	Net Profit ($mill)	*47.0*
						26.7%	55.1%	37.5%	37.1%	36.9%	36.5%	36.9%	39.1%	39.4%	37.9%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
						--	--	.2%	.9%	1.9%	1.9%	2.2%	--	2.2%	1.7%	*1.7%*	*1.7%*	AFUDC % to Net Profit	*2.0%*
						53.5%	41.9%	41.8%	46.7%	44.5%	47.8%	42.2%	45.8%	43.5%	37.4%	*37.0%*	*37.0%*	Long-Term Debt Ratio	*35.0%*
						46.5%	58.1%	58.2%	53.3%	55.5%	52.2%	57.8%	54.2%	56.5%	62.6%	*63.0%*	*63.0%*	Common Equity Ratio	*65.0%*
						415.4	308.0	310.8	342.0	334.3	383.7	373.9	419.5	465.3	540.5	*550*	*565*	Total Capital ($mill)	*590*
						315.0	312.2	284.7	258.6	260.1	342.8	401.2	451.5	537.5	607.4	*615*	*620*	Net Plant ($mill)	*625*
						7.0%	5.9%	8.8%	8.0%	8.8%	8.8%	9.0%	8.1%	7.8%	7.3%	*7.5%*	*8.0%*	Return on Total Cap'l	*9.0%*
						12.4%	7.4%	12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	*10.0%*	*10.5%*	Return on Shr. Equity	*12.0%*
						12.4%	7.4%	12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	*10.0%*	*10.5%*	Return on Com Equity E	*12.0%*
						1.9%	NMF	1.0%	.7%	1.5%	2.9%	2.3%	2.6%	2.5%	1.8%	*2.5%*	*2.8%*	Retained to Com Eq	*4.6%*
						85%	NMF	92%	94%	89%	79%	82%	79%	79%	82%	*78%*	*74%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 12/31/04
Total Debt $255.6 mill. Due in 5 Yrs $65.0 mill.
LT Debt $202.3 mill. LT Interest $12.0 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/04 $108.7 mill.
Obligation $154.6 mill.

Pfd Stock None

Common Stock 20,389,619 shs.

MARKET CAP: $700 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2001	2002	2003
% Change Retail Sales (KWH)	-1.6	+5.5	-0.7
Avg. Indust. Use (MWH)	4629	4624	4293
Avg. Indust. Revs. per KWH (¢)	4.11	4.40	4.37
Capacity at Peak (Mw)	768	763	812
Peak Load, Summer (Mw)	664	714	690
Annual Load Factor (%)	48.1	59.1	48.1
% Change Customers (avg.)	+.5	+1.0	+1.6
Fixed Charge Cov. (%)	352	388	352

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '01-'03 to '08-'10
Revenues	3.5%	5.0%	.5%
"Cash Flow"	1.5%	1.5%	.5%
Earnings	1.0%	7.0%	6.0%
Dividends	1.0%	1.0%	.5%
Book Value	1.5%	3.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	98.3	74.0	79.4	95.4	347.1
2003	128.5	82.6	87.9	102.5	401.5
2004	135.4	85.4	86.8	117.3	424.9
2005	*140*	*92.0*	*94.0*	*109*	*435*
2006	*144*	*96.0*	*97.0*	*113*	*450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.64	.26	.60	.19	1.69
2003	.53	.33	.56	.29	1.71
2004	.74	.30	.48	.25	1.77
2005	*.71*	*.33*	*.55*	*.31*	*1.90*
2006	*.74*	*.35*	*.57*	*.34*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.331	.331	.333	.333	1.33
2002	.333	.333	.336	.336	1.34
2003	.336	.336	.338	.338	1.35
2004	.338	.338	.342	.342	1.36
2005	.342				

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to nearly 132,000 customers in a 250-square-mile area of Dane County and gas service to 129,000 customers in 1,375 square miles in seven counties in Wisconsin. Electric revenue breakdown, '04: residential, 35%; commercial, 49%; industrial, 6%; public authorities, 8%; other, 2%. Generating sources, '04: fossil-fueled steam, 65%; purchased power, 33%; other, 2%. Fuel costs: 43% of revenues. '04 reported deprec. rate: electric, 3.4%; gas, 3.3%. Has 693 employees, 18,000 stockholders. Chairman, President & CEO: Gary J. Wolter. Inc.: Wisconsin. Address: 133 South Blair St., P.O. Box 1231, Madison, WI 53701-1231. Tel.: 608-252-7000. Internet: www.mge.com.

MGE Energy still expects to finish construction on the West Campus Cogeneration Facility by mid-year or so. Located on the University of Wisconsin-Madison (UW-M) campus, the $185 million gas-fired plant will have the capacity to produce approximately 150 megawatts of electricity. The residual thermal energy that is wasted in standard electrical power plants will also be used. Captured steam will heat the UW-M campus; chilled water will provide air conditioning during the summer. MGE also recently inked a 20-year purchase power agreement for 40 megawatts of renewable energy from a new wind farm proposed for the Waupun area. Both projects should help MGE meet its power needs and burnish its well-established reputation as an environmentally responsible corporate citizen.

Prospects for the next decade or so remain favorable. It is estimated that customers' peak demand will grow 3% a year above and beyond the impact of energy-savings initiatives. Favorable demographics within MGE's south-central Wisconsin service area are largely to thank. Dane County's population, including the city of Madison and UW-M, has been growing at an annual clip of 1.5%. That is nearly 50% higher than the national average.

Investment in the transmission grid should help avoid power disruptions. MGE is currently working with American Transmission Co. (ATC) on a plan for some $95 million of improvements on the electric transmission system that serves MGE customers. MGE is part-owner in ATC and earns a return on its investment in ATC's transmission assets.

Untimely MGE shares are probably best suited for income-oriented investors. Their current yield, at 4.0%, is relatively attractive. What's more, the prospect for future, albeit modest, dividend increases is good, as the company has increased its dividends annually for the past 28 years. Still, capital appreciation potential to 2008-2010 is negligible, particularly given the stock's strong run up in price over the past few years and an above-average valuation based on forward earnings.

Nils C. Van Liew *April 1, 2005*

(A) Excl. nonrecurring loss: '96, 42¢. Next earnings report due late April. (B) Dividends historically paid in mid-March, June, September, December. ■ Dvd. reinvestment plan available. (C) Incl. deferred charges. In '01: $27.1 mill., $1.59/sh. (D) In millions, adjusted for stock splits. (E) Rate allowed on common equity in '02: 12.9%; earned on average common equity, '02: 13.0%. Regulatory Climate: Above Average

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	90

VECTREN CORP. NYSE-VVC

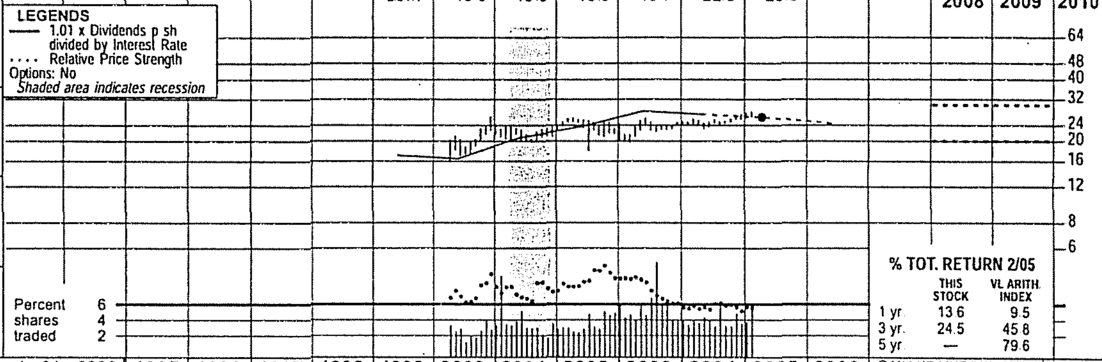
RECENT PRICE 26.25 | P/E RATIO 15.9 (Trailing: 18.2 / Median: NMF) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.5% | VALUE LINE

High:	26.5	24.4	26.1	26.1	27.1	28.0
Low:	15.8	19.8	18.0	19.7	22.9	25.8

Target Price Range 2008 | 2009 | 2010

TIMELINESS 3 Raised 4/1/05
SAFETY 2 Lowered 1/5/01
TECHNICAL 3 Lowered 9/10/04
BETA .75 (1.00 = Market)

LEGENDS
—— 1.01 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+15%)	*8%*
Low	20	(-25%)	*-1%*

Insider Decisions

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

Institutional Decisions

	2Q2004	3Q2004	4Q2004
to Buy	71	79	93
to Sell	75	54	49
Hld's(000)	30370	29257	29841

% TOT. RETURN 2/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.6	9.5
3 yr.	24.5	45.8
5 yr.	—	79.6

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. Data prior to the merger are pro forma.

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
--	--	--	--	16.88	26.84	32.05	26.53	21.00	*22.25*	*22.95*	*23.90*	Revenues per sh	*26.75*
--	--	--	--	2.87	2.88	2.89	3.43	3.17	3.25	*3.70*	*3.90*	"Cash Flow" per sh	*4.30*
--	--	--	--	1.48	1.17	1.08	1.68	1.56	1.44	*1.75*	*1.85*	Earnings per sh A	*1.95*
--	--	--	--	.95	.98	1.03	1.07	1.11	1.15	*1.19*	*1.23*	Div'd Decl'd per sh B■	*1.35*
--	--	--	--	--	2.67	3.48	3.22	3.12	*3.45*	*2.95*	*3.05*	Cap'l Spending per sh	*3.10*
--	--	--	--	11.55	11.91	12.53	12.79	14.18	*14.45*	*15.00*	*15.60*	Book Value per sh C	*17.25*
--	--	--	--	61.47	61.42	67.70	68.01	75.60	*76.00*	*76.20*	*76.50*	Common Shs Outst'g D	*77.40*
--	--	--	--	--	17.4	20.3	14.2	14.8	17.3	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
--	--	--	--	--	1.13	1.04	.78	.84	.92	*Value Line*		Relative P/E Ratio	*.85*
--	--	--	--	--	4.8%	4.7%	4.5%	4.8%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*5.2%*
--	--	--	--	1037.4	1648.7	2170.0	1804.3	1587.6	1689.8	*1750*	*1830*	Revenues ($mill)	*2070*
--	--	--	--	90.8	72.0	73.1	114.0	111.2	109.6	*135*	*140*	Net Profit ($mill)	*150*
--	--	--	--	33.6%	32.2%	20.3%	25.4%	25.3%	*25.0%*	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
--	--	--	--	--	--	7.7%	4.6%	4.5%	*4.0%*	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
--	--	--	--	40.0%	45.8%	54.4%	52.3%	50.0%	*49.5%*	*48.5%*	*47.5%*	Long-Term Debt Ratio	*44.5%*
--	--	--	--	58.4%	53.0%	45.5%	47.7%	50.0%	*50.5%*	*51.5%*	*52.5%*	Common Equity Ratio	*55.5%*
--	--	--	--	1215.8	1380.6	1863.1	1824.4	2144.7	*2170*	*2215*	*2265*	Total Capital ($mill)	*2410*
--	--	--	--	1336.3	1555.8	1595.0	1648.1	2003.7	*2130*	*2205*	*2285*	Net Plant ($mill)	*2465*
--	--	--	--	8.6%	6.1%	5.5%	7.7%	6.6%	*6.5%*	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
--	--	--	--	12.5%	9.6%	8.6%	13.1%	10.4%	*10.0%*	*11.5%*	*12.0%*	Return on Shr. Equity	*11.5%*
--	--	--	--	12.6%	9.7%	8.5%	13.1%	10.4%	*10.0%*	*11.5%*	*12.0%*	Return on Com Equity E	*11.5%*
--	--	--	--	4.8%	1.5%	.3%	4.8%	3.0%	*2.0%*	*3.5%*	*4.0%*	Retained to Com Eq	*3.5%*
--	--	--	--	63%	85%	96%	63%	71%	*80%*	*68%*	*66%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 9/30/04
Total Debt $1398.9 mill. Due in 5 Yrs $395.9 mill.
LT Debt $1065.0 mill. LT Interest $61.0 mill.
(LT interest earned: 3.4x)

Pension Assets-12/03 $147.8 mill. **Oblig.** $222.7 mill.

Pfd Stock $.1 mill. **Pfd Div'd** --
2,277 shs. 8.5%, no par. redeem. at $100

Common Stock 75,981,012 shs. as of 10/31/04
MARKET CAP: $2.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2001	2002	2003
% Change Retail Sales (KWH)	+.3	+6.3	-4.4
Avg. Indust. Use (MWH)	12320	12772	15593
Avg. Indust. Revs. per KWH (¢)	4.17	5.32	5.78
Capacity at Peak (Mw)	1448	1528	1478
Peak Load, Summer (Mw)	1209	1258	1272
Annual Load Factor (%)	55.0	56.1	55.4
% Change Customers (yr-end)	+.7	+1.4	.8
Fixed Charge Cov. (%)	164	262	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '01-'03 to '08-'10
Revenues	--	--	*Nil*
"Cash Flow"	--	--	*4.5%*
Earnings	--	--	*4.5%*
Dividends	--	--	*3.5%*
Book Value	--	--	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2002	630.4	380.1	304.3	489.5	1804.3
2003	626.7	268.4	240.3	452.2	1587.6
2004	645.4	276.7	254.4	513.3	1689.8
2005	*675*	*295*	*275*	*505*	*1750*
2006	*695*	*315*	*295*	*525*	*1830*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2002	.67	.18	.20	.63	1.68
2003	.82	.06	.10	.58	1.56
2004	.72	.04	.13	.55	1.44
2005	*.85*	*.10*	*.15*	*.65*	*1.75*
2006	*.90*	*.10*	*.15*	*.70*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.255	.255	.255	.265	1.03
2002	.265	.265	.265	.275	1.07
2003	.275	.275	.275	.285	1.11
2004	.285	.285	.285	.295	1.15
2005	.295				

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. Has a customer base of 1,110,000. 2003 Elect. (gas) revs: resid., 34% (67%); commer., 27% (25%); indust., 37% (8%); other, 2% (nil). Revenue sources: Elect., 23%; Gas, 77%. Fuel costs: elect., 31%; gas, 69%. Also provides energy-related products and services and has an investment subsidiary. Est'd plant age: electric, 10 years. '03 deprec. rate: 3.5%. Has 1,858 employees. 12,689 shareholders. Chairman, Chief Executive Officer, and President: Niel C. Ellerbrook. Inc.: IN. Address: 20 Northwest 4th St., Evansville, Indiana 47741. Tel.: 812-465-5300. Internet: www.vectren.com.

Vectren's unregulated businesses are growing at a healthy rate. ProLiance, a 61%-owned affiliate, trades and markets natural gas, sells gas to the company's two regulated subsidiaries, and services other large end-use customers. It contributed about $0.30 a share to corporate net last year and may be more profitable in 2005. But a note of caution: ProLiance lost a lawsuit in which it was accused of breach of contract. An unfavorable outcome on appeal could be materially adverse to earnings. (We would treat any charge as nonrecurring.) VVC also owns and operates two low-sulfur coal mines that not only supply company plants but sell one million tons a year in the open market. Higher contract prices point to improved earnings in 2005. In addition, the company has a 50% stake in Pace Carbon Synfuels, which earns tax credits through the sale of coal-based synthetic fuels. These enterprises should account for 25% of company net this year. Moreover, we expect them to grow at a faster rate than the regulated utilities through 2008-2010.

The company awaits a rate order on its filing in Ohio. The request calls for an increase of $25 million and an allowed return of 12.25% to recover the cost of operating and expanding the 5,200-mile distribution system. The application also includes a tariff that would enable VVC to support the reduction of energy consumption. The petition addresses nongas costs only. A commission order is due shortly.

Earnings may set a record in 2005. Positives include last year's rate hikes in northern and southern Indiana and the likelihood of an increase in Ohio. The company will also benefit from recovery of environmental expenditures to reduce emissions of nitrogen oxide. But higher pension costs are a negative. All told, we estimate a 22% rise in 2005 earnings, to $1.75 a share. Improved results in the unregulated area should help lift earnings next year.

Income-oriented investors might take a look here. Based on our forecast of earnings gains to 2008-2010, dividend growth prospects over the same timeframe are more than double those of the group. What's more, these shares are of good quality.

Arthur H. Medalie — *April 1, 2005*

(A) Diluted EPS. Next earnings report due late Apr. Excl. nonrecur. gain (losses): '00, 8¢; '01, (13¢); '03, (6¢); incl. charges for merger costs: '00, 60¢; '01, 17¢. (B) Div'ds historically paid in early March, early June, early September, and early December. ■Div'd reinvest. plan avail. (C) Incl. intang. in '03, $3.89/sh. (D) In millions. (E) Electric rate base determination: fair value. Rate allowed on common equity in '95: 12.25%. Earned on avg. com. eq. '03: 11.5%. Regulatory Climate: Above Average.

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

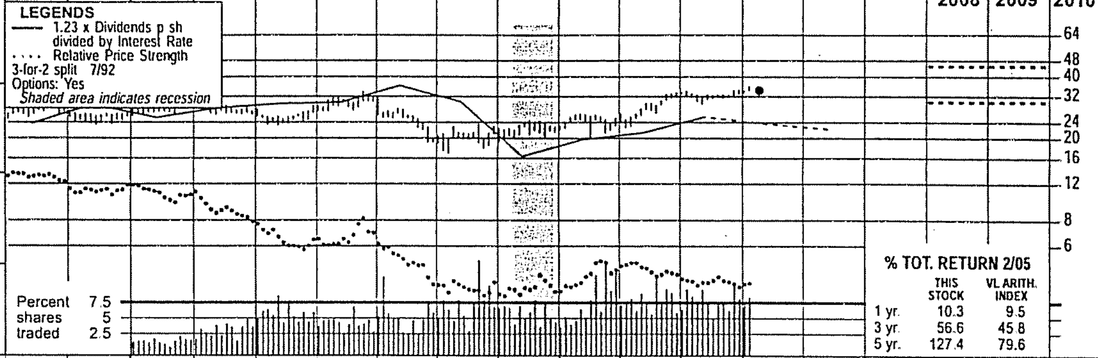
WISCONSIN ENERGY NYSE-WEC

RECENT PRICE 34.40 | P/E RATIO 15.4 (Trailing: 18.6, Median: 15.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 3 Raised 2/18/05
SAFETY 2 Lowered 7/11/97
TECHNICAL 3 Raised 3/25/05
BETA .70 (1.00 = Market)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	27.5	30.9	32.0	29.1	34.0	31.6	23.6	24.6	26.5	33.7	34.6	36.1	
Low:	23.1	25.8	26.0	23.0	27.0	19.1	16.8	19.1	20.2	22.6	29.5	33.3	

LEGENDS
—— 1.23 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 7/92
Options: Yes
Shaded area indicates recession



Target Price Range
2008 | 2009 | 2010

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	10%
Low	30	(-15%)	Nil

Insider Decisions

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

Institutional Decisions

	2Q2004	3Q2004	4Q2004
to Buy	104	94	111
to Sell	117	109	99
Hld's(000)	66836	70040	69112

% TOT. RETURN 2/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	10.3	9.5
3 yr.	56.6	45.8
5 yr.	127.4	79.6

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
14.78	14.28	15.23	15.05	15.61	15.99	15.98	15.88	15.86	17.13	19.11	28.28	34.04	32.20	34.24	29.33	*30.75*	*32.50*	Revenues per sh	*36.75*
3.32	3.28	3.33	3.22	3.84	3.81	4.28	4.25	2.96	4.13	4.53	4.48	5.44	5.68	5.71	5.16	*5.80*	*6.15*	"Cash Flow" per sh	*7.00*
1.92	1.85	1.87	1.67	1.81	1.67	2.13	1.97	.54	1.65	1.88	1.08	1.84	2.32	2.26	1.85	*2.30*	*2.45*	Earnings per sh A	*2.75*
1.09	1.16	1.23	1.29	1.34	1.40	1.46	1.51	1.54	1.56	1.56	1.37	.80	.80	.80	.83	*.88*	*.92*	Div'd Decl'd per sh B ■	*1.04*
2.04	2.09	2.40	3.11	3.43	2.76	2.50	3.53	3.13	3.52	4.44	5.29	6.03	5.07	5.89	5.70	*7.05*	*7.50*	Cap'l Spending per sh	*7.75*
13.01	13.70	14.35	14.97	15.67	16.01	16.89	17.42	16.51	16.46	16.89	17.00	17.81	18.44	19.92	21.31	*22.75*	*24.30*	Book Value per sh C	*29.25*
101.04	101.04	101.04	103.09	105.32	108.94	110.82	111.68	112.87	115.61	118.90	118.65	115.42	116.03	118.43	116.99	*117.00*	*117.00*	Common Shs Outst'g D	*117.00*
9.8	10.6	12.1	15.6	15.2	15.2	13.1	14.3	47.3	18.0	13.3	18.7	12.1	10.5	12.4	17.5	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.74	.79	.77	.95	.90	1.00	.88	.90	2.73	.94	.76	1.22	.62	.57	.71	.93	*Value*	*Line*	Relative P/E Ratio	*.90*
5.8%	6.0%	5.4%	5.0%	4.9%	5.5%	5.2%	5.4%	6.0%	5.2%	6.3%	6.8%	3.6%	3.3%	2.8%	2.6%	*estim*	*ates*	Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 12/31/04
Total Debt $3678.5 mill. Due in 5 Yrs $1641.3 mill.
LT Debt $3239.5 mill. LT Interest $186.3 mill.
Incl. $191.1 mill. capitalized leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $50.4 mill.

Pension Assets-12/04 $998.5 mill. Oblig. $1.2 bill.
Pfd Stock $30.4 mill. Pfd Div'd $1.2 mill.
260,000 shs 3.60%, $100 par, callable at $101;
44,498 shs. 6%, $100 par.
Common Stock 116,985,602 shs.
as of 1/31/05
MARKET CAP: $4.0 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
1770.5	1773.8	1789.6	1980.0	2272.6	3354.7	3928.5	3736.2	4054.3	3431.1	*3600*	*3800*	Revenues ($mill)	*4300*
235.2	219.3	61.9	189.3	231.5	132.0	218.8	270.8	269.2	221.2	*270*	*290*	Net Profit ($mill)	*325*
37.1%	36.4%	33.4%	32.7%	33.8%	43.7%	40.9%	37.4%	35.5%	37.5%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
3.8%	3.9%	16.7%	5.7%	5.8%	12.3%	6.9%	4.1%	6.9%	10.0%	*7.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
41.8%	41.7%	44.7%	47.5%	48.8%	58.9%	62.2%	59.8%	59.9%	56.2%	*48.0%*	*51.5%*	Long-Term Debt Ratio	*48.0%*
57.2%	57.4%	54.4%	51.7%	45.9%	40.5%	37.2%	39.6%	39.6%	43.3%	*51.5%*	*48.0%*	Common Equity Ratio	*51.5%*
3269.4	3391.9	3425.8	3682.6	4372.8	4979.9	5523.8	5400.3	5963.3	5762.3	*5175*	*5900*	Total Capital ($mill)	*6625*
2910.6	3057.9	3185.0	3238.4	3846.6	4152.4	4188.0	4398.8	5926.1	5903.1	*6320*	*6765*	Net Plant ($mill)	*8050*
8.8%	8.0%	3.4%	6.6%	6.7%	4.7%	5.8%	7.1%	6.3%	5.6%	*7.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
12.4%	11.1%	3.3%	9.8%	10.3%	6.4%	10.5%	12.5%	11.3%	8.8%	*10.0%*	*10.0%*	Return on Shr. Equity	*9.5%*
12.5%	11.2%	3.3%	9.9%	10.9%	6.5%	10.6%	12.6%	11.4%	8.8%	*10.5%*	*10.0%*	Return on Com Equity E	*9.5%*
4.0%	2.6%	NMF	6%	1.9%	NMF	6.0%	8.3%	7.4%	4.9%	*6.5%*	*6.5%*	Retained to Com Eq	*6.0%*
68%	77%	NMF	94%	84%	NMF	43%	35%	35%	45%	*39%*	*38%*	All Div'ds to Net Prof	*39%*

ELECTRIC OPERATING STATISTICS

	2002	2003	2004
% Change Retail Sales (KWH)	+2.8	+.8	+1.7
Avg Indust. Use (MWH)	15698	16127	16482
Avg Indust. Revs. per KWH (¢)	4.34	4.55	4.71
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6231	6376	5789
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.1	+1.3
Fixed Charge Cov. (%)	260	256	248

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	7.5%	13.0%	2.5%
"Cash Flow"	4.5%	7.5%	4.0%
Earnings	2.0%	9.5%	4.0%
Dividends	-5.0%	-12.0%	4.5%
Book Value	2.5%	3.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	986.0	870.9	869.8	1009.5	3736.2
2003	1229.2	914.3	878.5	1032.3	4054.3
2004	1065.9	716.4	696.6	952.2	3431.1
2005	*1100*	*750*	*750*	*1000*	*3600*
2006	*1150*	*800*	*800*	*1050*	*3800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.75	.43	.50	.64	2.32
2003	.79	.37	.47	.64	2.26
2004	.69	.17	.26	.73	1.85
2005	*.70*	*.30*	*.50*	*.80*	*2.30*
2006	*.80*	*.30*	*.55*	*.80*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.20	.20	.20	.20	.80
2002	.20	.20	.20	.20	.80
2003	.20	.20	.20	.20	.80
2004	.20	.21	.21	.21	.83
2005	.22				

BUSINESS: Wisconsin Energy Corporation (WEC) is a holding company for We Energies, which provides electric, gas & steam service in WI & upper MI. Customers: 1.1 mill. elec., 1 mill. gas. Acq'd Edison Sault Electric 5/98; WICOR 4/00. Discontinued pump-manufacturing ops. in '04. Elec. rev. breakdown, '04: res'l, 35%; small comm'l & ind'l, 32%; large comm'l & ind'l, 26%; other, 7%. Generating sources, '04: coal, 61%; nuclear, 24%; hydro & other, 2%; purchased, 13%. Fuel costs: 43% of revs. '04 reported deprec. rate (utility): 4.2%. Has 5,700 employees, 62,000 com. stockholders. Chairman, President & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 2949, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

The Wisconsin Supreme Court will have an expedited hearing of a matter concerning Wisconsin Energy's "Power the Future" plan. The company is appealing a judge's ruling, which stated that the Wisconsin commission didn't follow proper procedures when it granted Wisconsin Energy permission to build the first of two coal-fired units that are set to come on line in 2009 and 2010. The builder has agreed to delay by two months (to July 1, 2005) a provision in the contract that adds a cost escalator if construction has not begun by then. This could boost the cost of the two coal units, which is already over $2 billion, by up to $260 million. A lengthy delay would also prevent the plant from coming on line when it is needed. Power the Future also calls for the addition of two gas-fired units (the first of which is scheduled to go on line in July), but these facilities haven't been nearly as controversial as the coal plants because gas is more environmentally friendly.

Earnings should return to a more normal level this year after a depressed tally in 2004. Last year, the cost of severance programs reduced earnings by $0.13 a share, and debt-redemption costs took $0.09 a share off the bottom line. We assume no such costs in 2005. The expense reduction from the severance should add $0.15 to share net, the income from the first gas-fired unit of Power the Future should add $0.07 a share, and the utility ought to benefit from customer growth and a return to normal weather patterns. This should outweigh negative factors that include the cost of an additional nuclear refueling outage, higher benefits expenses, and the effect of a lag in the recovery of higher fuel costs. Our estimate is at the low end of the company's target of $2.30-$2.40 a share.

The utility plans to file a general rate case later this year. New electric and gas tariffs would likely go into effect in early 2006. Assuming some rate relief next year, we figure earnings will rise 6%-7%.

The board of directors has raised the quarterly dividend by one cent a share (4.8%), but this stock's yield is still well below average by utility standards. Total-return potential to 2008-2010 is only average for a utility.

Paul E. Debbas, CFA *April 1, 2005*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '99, (9¢); '00, 19¢ net; '01, 1¢ net; '02, (88¢); '03, (20¢) net; '04, (81¢); gain on discontinued operations: '04, $1.54. '03 earnings don't add due to rounding. Next earnings report due late Apr. (B) Div'ds historically paid in early Mar., June, Sept., Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '04: $11.04/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '00: 12.2%; earned on avg. com. eq., '04: 9.1%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	55

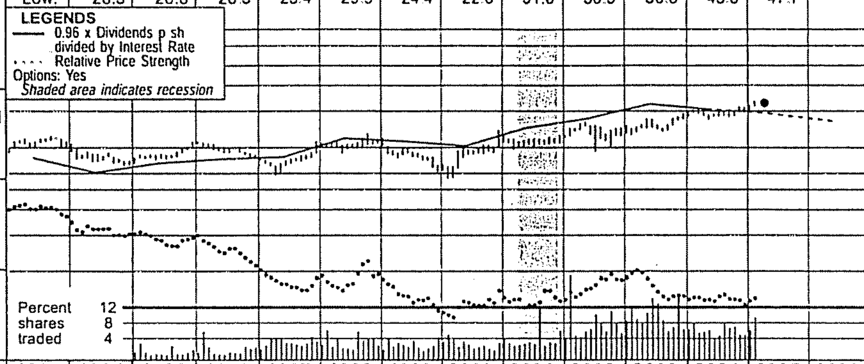
WPS RESOURCES NYSE-WPS

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
52.53	12.2 (Trailing: 12.9; Median: 13.0)	0.66	4.3%

VALUE LINE

TIMELINESS 3 Raised 2/11/05
SAFETY 2 Lowered 4/4/03
TECHNICAL 3 Raised 3/25/05
BETA .75 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	33.6	34.3	34.4	34.3	37.5	35.8	39.0	36.8	42.7	46.8	50.5	54.9
Low:	26.3	26.8	28.3	23.4	29.9	24.4	22.6	31.0	30.5	36.8	43.5	47.7



Target Price Range

2008	2009	2010

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+25%)	9%
Low	45	(-15%)	1%

Insider Decisions

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

Institutional Decisions

	2Q2004	3Q2004	4Q2004
to Buy	81	76	84
to Sell	56	54	57
Hld's(000)	10959	11071	11869

% TOT. RETURN 2/05

	THIS STOCK	VL ARITH. INDEX
1 yr	14.7	9.5
3 yr	57.6	45.8
5 yr	191.9	79.6

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
25.59	25.73	27.24	26.62	28.48	28.20	30.12	35.91	36.76	40.06	40.91	72.68	85.80	83.55	117.07	130.75	132.70	129.25	Revenues per sh	139.40
4.79	4.80	5.03	5.09	5.00	4.56	5.06	4.71	5.37	5.01	5.34	6.11	5.27	5.91	6.23	8.05	8.85	9.35	"Cash Flow" per sh	11.70
1.98	2.00	2.23	2.35	2.47	2.21	2.32	2.00	2.13	1.76	2.24	2.43	2.74	2.74	2.76	4.07	4.10	4.20	Earnings per sh A	4.30
1.60	1.64	1.68	1.72	1.76	1.80	1.84	1.88	1.92	1.96	2.00	2.04	2.08	2.12	2.16	2.20	2.24	2.28	Div'd Decl'd per sh B ■	2.40
3.17	2.68	2.84	3.99	2.87	2.87	3.35	3.55	2.44	3.57	4.93	5.94	7.98	7.16	4.77	5.35	7.30	6.90	Cap'l Spending per sh	6.75
16.30	16.26	16.13	17.33	18.18	18.69	19.39	19.56	20.00	19.48	19.97	20.21	22.96	24.45	27.18	29.00	31.05	31.40	Book Value per sh C	37.50
22.89	22.89	22.89	23.85	23.90	23.90	23.90	23.90	23.90	26.55	26.85	26.85	31.18	32.01	36.91	37.40	37.60	40.00	Common Shs Outst'g D	40.60
11.4	11.0	11.3	12.6	13.7	13.0	12.8	15.7	13.1	18.9	13.2	12.2	12.5	14.0	14.9	11.5	Bold figures are		Avg Ann'l P/E Ratio	13.0
.86	.82	.72	.76	.81	.85	.86	.98	.76	.98	.75	.79	.64	.76	.85	.61	Value Line		Relative P/E Ratio	.85
7.1%	7.4%	6.6%	5.8%	5.2%	6.2%	6.2%	6.0%	6.9%	5.9%	6.7%	6.9%	6.1%	5.5%	5.3%	4.7%	estimates		Avg Ann'l Div'd Yield	4.3%

CAPITAL STRUCTURE as of 9/30/04
Total Debt $1018.7 mill. Due in 5 Yrs $182.3 mill.
LT Debt $868.8 mill. LT Interest $44.4 mill.
(LT interest earned: 4.3x)
Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/03 $567.9 mill. **Oblig.** $610.9 mill.
Pfd Stock $51.1 mill. **Pfd Div'd** $3.1 mill.
512,000 shs. 5.00% to 6.88%, callable $101 to $107.50; sinking fund began 11/1/79. All cumulative, $100 par.

Common Stock 37,386,727 shs. as of 10/31/04
MARKET CAP: $2.0 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
719.8	858.3	878.3	1063.7	1098.5	1951.6	2675.5	2674.9	4321.3	4890.6	4990	5170	Revenues ($mill)	5660
58.5	50.5	54.0	49.8	62.7	67.4	80.7	94.4	94.5	153.7	155	165	Net Profit ($mill)	175
34.5%	32.5%	34.0%	32.3%	32.2%	6.7%	5.6%	20.8%	26.3%	26.0%	26.0%	26.0%	Income Tax Rate	26.0%
.4%	.5%	.4%	--	--	--	--	3.2%	2.5%	3.0%	4.0%	4.0%	AFUDC % to Net Profit	3.0%
37.3%	37.1%	36.5%	35.7%	47.8%	50.6%	47.1%	48.3%	45.3%	46.0%	44.5%	42.5%	Long-Term Debt Ratio	42.5%
56.4%	56.7%	57.4%	53.8%	43.9%	41.6%	46.3%	45.8%	52.1%	51.5%	53.5%	55.0%	Common Equity Ratio	55.5%
821.2	824.5	833.0	961.4	1222.0	1303.9	1544.8	1708.3	1926.2	2110	2190	2280	Total Capital ($mill)	2745
870.1	892.9	886.4	820.1	863.7	905.1	1463.6	1610.2	1828.7	1880	1975	2040	Net Plant ($mill)	2055
8.5%	7.4%	7.8%	6.4%	6.2%	6.8%	6.8%	7.0%	6.1%	9.0%	8.5%	8.5%	Return on Total Cap'l	8.0%
11.4%	9.7%	10.2%	8.0%	9.8%	10.5%	9.9%	10.7%	9.0%	13.5%	13.0%	13.0%	Return on Shr. Equity	11.5%
11.9%	10.1%	10.6%	9.0%	11.1%	11.9%	10.8%	11.7%	9.1%	14.0%	13.0%	13.0%	Return on Com Equity E	11.5%
2.5%	.5%	1.0%	NMF	1.2%	1.9%	2.7%	3.1%	2.0%	6.5%	6.0%	6.0%	Retained to Com Eq	5.0%
81%	95%	91%	102%	85%	80%	76%	74%	79%	55%	56%	55%	All Div'ds to Net Prof	57%

ELECTRIC OPERATING STATISTICS

	2001	2002	2003
% Change Retail Sales (KWH)	+1.6	+3.6	+1.0
Avg. Indust. Use (KWH)	17727	16982	16089
Avg. Indust. Revs. per KWH (¢)	3.10	3.72	3.76
Capacity at Peak (Mw)	1978	1947	2285
Peak Load, Summer (Mw)	2173	1947	1888
Annual Load Factor (%)	70.6	74.5	74.5
% Change Customers (yr-end)	+1.5	+1.7	+1.6
Fixed Charge Cov. (%)	173	197	182

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '01-'03 to '08-'10
Revenues	13.5%	20.5%	5.5%
"Cash Flow"	1.5%	3.0%	10.5%
Earnings	1.5%	7.0%	6.5%
Dividends	2.0%	2.0%	2.0%
Book Value	3.5%	5.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	671.3	579.4	609.6	814.6	2674.9
2003	1281.8	971.9	989.3	1078.3	4321.3
2004	1373.3	1045.9	1072.5	1398.9	4890.6
2005	1450	1110	1140	1290	4990
2006	1500	1150	1180	1340	5170

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.89	.36	.77	.72	2.74
2003	.92	.08	1.04	.72	2.76
2004	1.22	.26	.99	1.60	4.07
2005	1.40	.30	1.00	1.40	4.10
2006	1.45	.30	1.00	1.45	4.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.515	.515	.525	.525	2.08
2002	.525	.525	.535	.535	2.12
2003	.535	.535	.545	.545	2.16
2004	.545	.545	.555	.555	2.20
2005	.555				

BUSINESS: WPS Resources Corporation is a holding company for subsidiaries that provide products and services in both regulated and nonregulated energy markets. Acq'd Upper Peninsula Energy 9/98. 2003 revenues: electric, 17%; gas, 10%; nonregulated energy and other, 73%. Electric revenue breakdown, '03: residential, 36%; commercial and industrial, 50%; other, 14%. Generating sources, '03, regul: coal, 61%; nuclear, 18%; hydro, 2%; other and purchased, 19%. Fuel costs: 45% of revenues. '03 deprec. rate: 3.6%. Est'd plant age: 9 years. Has 3,080 employees, 22,172 common stockholders. Chairman, President & CEO: Larry L. Weyers. Incorporated: WI. Address: 700 N. Adams Street, Green Bay, WI 54307. Telephone: 800-236-1551. Internet: www.wpsr.com.

WPS Resources has received higher rates; two requests are pending. Last December, the Wisconsin regulators granted the company increased electric rates of $60.7 million and higher posted gas tariffs of $5.6 million. The decision allows an 11.5% return on equity, down from the previous 12.0%. The reduced return is the result of lower interest rates. The order reimburses the company for higher employee medical benefits, upgrades to the generation and distribution systems, and construction work in progress at the 500 megawatt (mw) coal-fired Weston 4 plant (See below). It also covers the cost of operating more expensive gas-fired peaking plants and buying increased amounts of energy from outside suppliers. Separately, WPS awaits orders on a $7.2 million filing for an unplanned outage at the Kewaunee nuclear facility and on a request in Michigan for $5.7 million.

The company is building a coal-fired plant. WPS has begun construction of a 500-megawatt (mw) unit at an estimated cost of $770 million. The location at the existing Weston site will reduce costs by sharing fixed charges with the three units already in operation. Dairyland has agreed to take a 30% interest in the facility, which is scheduled to go on line in 2008. The increased capacity will offset the loss of Kewaunee, whose sale to Dominion was recently approved by the Wisconsin regulators. Looking further down the road, WPS plans to build another 500-mw base-load plant with Alliant Energy in 2011.

Current-year earnings may only match 2004's strong performance. Thanks to the recent rate increase, electric and gas margins will rise. A full year of the acquisition of Advantage Energy, an electric power marketer, and a probable 2%-3% rise in retail energy sales are additional pluses. But higher pension costs and downtime for refueling Kewaunee suggest only flat earnings in 2005. Likely improvement in unregulated operations points to a modest gain in 2006.

The yield is a cut above the industry norm. And based on our projection of steady earnings gains after this year, dividend growth prospects to 2008-2010 are almost double those of its peers. Income-oriented investors might take a look here.

Arthur H. Medalie *April 1, 2005*

(A) Diluted EPS. Excl. gains, (loss): '97, 12¢; '00, 10¢; '02, 68¢; '03, 10¢; '04, (35¢). Next egs. report due late Apr. (B) Div'ds historically paid in late Mar., late June, late Sept., and late Dec. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '03, $127.7 mill., $3.46/sh. (D) In millions. (E) Rate base determination: Net orig. cost. Rate allowed in Wisc. on com. equity in '04: 11.5%; earned on avg. com. equity, '03: 10.3%. Reg. Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 37

Refer to the Moul Testimony, page 5, lines 15 through 22. Provide a more detailed explanation of how increases in operating and capital costs due to the Clean Air Act ("CAA") create added risk for the company.

Response

Generally, the capital requirements and operating expenses associated with CAA compliance do not provide incremental revenues to a utility, other than those obtained through rate adjustments that affect all customer rates, as approved by the regulatory authority. Unlike other investments by an electric utility that may add to revenues through additional capacity or expansion of the scope of sales opportunities, CAA investment will not add revenues in this regard. Moreover, CAA investment will not enhance an electric utility's efficiency and/or productivity (i.e., it is not capital that will promote a reduction in operating expense). The capital and operating costs associated with CAA investment will merely increase electric rates.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 39

Explain why the presence of an environmental surcharge that authorizes the monthly recovery of CAA-related operations and capital costs does not eliminate any additional risk from increased CAA-related expenditures.

Response

The mechanism for the recovery of the CAA-related expenditures provides the Company with a number of advantages to the extent that its operating and capital costs are recoverable from retail customers. However, due to allocation issues associated with the implementation of the environmental surcharge, the Company has been able to only partially recover its costs associated with these expenditures. The surcharge as it is applied reduces attrition and regulatory lag associated with the recovery of non-revenue producing and non-expense reducing investment. Otherwise, it would be necessary to file rate cases for recovery of these costs, and the mechanism avoids the "rate shock" associated with a large adjustment in rates for these expenditures. However, there continues to be risks associated with changing environmental regulations, which may involve additional compliance measures, and the rate impact of CAA investments which make the Company's rates less competitive with alternative energy sources.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 39

Explain why the presence of an environmental surcharge that authorizes the monthly recovery of CAA-related operations and capital costs does not eliminate any additional risk from increased CAA-related expenditures.

Response

The mechanism for the recovery of the CAA-related expenditures provides the Company with a number of advantages. It reduces attrition and regulatory lag associated with the recovery of non-revenue producing and non-expense reducing investment. Otherwise, it would be necessary to file rate cases for recovery of these costs, and the mechanism avoids the "rate shock" associated with a large adjustment in rates for these expenditures. However, there continues to be risks associated with changing environmental regulations, which may involve additional compliance measures, and the rate impact of CAA investments which make the Company's rates less competitive with alternative energy sources.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 40

How many of the companies included in Mr. Moul's Electric Group have surcharges that authorize the monthly recovery of capital costs and operation and maintenance costs related to the CAA and other federal, state, and local environmental requirements that apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal?

Response

Mr. Moul is aware that Vectren Corporation has an environmental surcharge available.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 41

The Moul Testimony, page 6, line 19, references "pressures from alternative providers." Provide the names of each alternative provider and the product that each is able to provide to Kentucky Power's industrial customers.

Response

Mr. Moul was referring to alternatives, such as self-generation, fuel oil, coal, and natural gas, as alternative providers of energy.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 42

Refer to the Moul Testimony, page 8. AEP operates in the Eastern, Central and Southwestern states and is listed in *Value Line's* Electric Utility (Central) Industry category. Explain why only companies operating in the Great Lakes region of the U.S. were selected for the Electric Group.

Response

Companies outside these regions are geographically remote from Kentucky Power and have climate and electric supply fundamentals that make them distinctly dissimilar to the Company's electric business. Moreover, a geographic criteria specified in the Bluefield case which states:

> "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures." (emphasis supplied). Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 43 S. Ct. 675, 67 L.Ed. 1176, 1182-1183 (1923)."

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 43

Refer to the Moul Testimony, pages 9 through 13. Explain the basis for using the nine categories of relative risk that Kentucky Power used to compare itself to the S&P Utilities and the proxy group.

Response

In Mr. Moul's opinion, the ratios associated with these nine categories, along with the others shown on Schedules 2, 3, and 4, provide a reasonable basis to assess the relative position of a utility relative to its peer group, and the business sector in which it operates. Many of the financial ratios are considered in analysts' reports and credit rating agencies in their analysis of a company.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 44

Refer to the Moul Testimony, page 25, and Exhibit No. PRM-1, Schedule 7. Provide a detailed explanation of the derivation of the 5.5 percent growth rate.

Response

There were no specific weights assigned to the accounting variables that were analyzed in order to assess the growth rate that investors could reasonably expect for the Electric Group. The accounting variables, such as those listed in Schedules 6 and 7 were considered included projected growth rates in earnings per share as well as, dividends per share, book value per share, cash flow per share, and retention growth. Both historical performance and analysts' projections were considered. From the array of growth rates considered, analysts' forecasts of earnings per share growth were given emphasis. The parameters of the DCF model mandate that relatively greater weight should be given to earnings per share growth because, with no change in price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. In addition, Professor Myron Gordon, the foremost proponent of the DCF model in utility ratesetting, established that analysts' forecast of earnings per share growth provides the best measure of growth in the DCF model (see "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, spring 1989 by Gordon, Gordon & Gould).

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 45

Refer to the Moul Testimony, pages 25 and 26. Would it produce the same result to adjust the capitalization to reflect market capitalization rather than adjust the return? If no, explain why not.

Response

Mr. Moul has not made any calculations in this regard. It is Mr. Moul's opinion that if the market capitalization of a utility (or its proxy group) was used to calculate the weighted average cost of capital, then there would be no need for making the corresponding leverage adjustment to the cost of equity calculation using the DCF and CAPM models.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 46

Refer to the Moul Testimony, page 31. Explain how Kentucky Power benefited from the stock issuances described in the testimony.

Response

Kentucky Power must be in a capital attraction posture at all times in order to meet its public service obligation. As such, a flotation cost provision must be made in the cost of equity calculation, unless otherwise provided in the cost-of-service. Such an allowance would be required whether the utility issues equity directly in the market if its stock is traded, or whether this is accomplished through a parent company that provides external equity to the utility.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 47

Refer to the Moul Testimony, Exhibit No. PRM-1, Schedule 9, page 1 of 4.

a. While estimates below 8.0 percent have been eliminated from the sample, the highest observation, 13.75 percent, appears to be a remaining outlier in the sample. The next highest upper observation is 11.04 percent. Explain why it is reasonable to retain an obvious outlier from the calculations when low outliers have been eliminated.

b. The Discounted Cash Flow ("DCF") recommendation of 10.92 percent represents a weighted average of the two extreme points of the sample range, each with a 50 percent weight, with no regard for the distribution of the other sample points. Explain why it is reasonable to disregard the mean and median values using all the data points in the sample.

c. Refer to the Note 1 on page 1 of 4. Describe the nature of the debt instruments and provide the respective yields, and the dates the yields were calculated that were used as the basis for rejecting cost of equity returns below 8 percent.

Response

a. There is a relationship between risk and the required return on all financial assets. For the more risky asset class of common stocks, these returns must exceed the yields available on less risky corporate bonds. If an inadequate premium is indicated from the spread observed between a DCF calculated return and the yield on a corporate bond, then the DCF calculation provides an invalid return on a common stock in compensation for the addition risk of common equity. After that threshold return is achieved, all remaining DCF calculations provide a valid measure of an equity cost rate.

b. The model that was employed in Schedule 9 of Exhibit No. PRM-1 was taken directly from the FERC opinions noted (see the response to Item No. 48 of the Second Data Request of the Commission Staff). The specification of this model prescribed the use of the midpoint return.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

c. The nature of the debt instrument is the yield on A-rated public utility bonds. Mr. Moul determined that the prospective yield in this regard is 6.50% (see Moul Testimony at pages 35 through 38). The implied minimum differential in this regard would be 1.50% for a DCF calculation to provide a valid indication of the cost of equity.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 48

Refer to the Moul Testimony, pages 32 and 33, and the "Source of Model" reference on Exhibit No. PRM-1, Schedule 9, page 1 of 4. Provide copies of the FERC opinions cited.

Response

The requested orders are attached.

Witness: Paul R. Moul

92 FERC ¶ 61,070

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 445

Southern California Edison Company | Docket Nos. ER97-2355-000, ER98-1261-000 and ER98-1685-000

OPINION AND ORDER AFFIRMING IN PART, VACATING IN PART, AND REVERSING IN PART, INITIAL DECISION

Issued: July 26, 2000

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO.445

Southern California Edison Company

Docket Nos. ER98-2355-000 ER98-1261-000 and ER98-1685-000

OPINION AND ORDER
AFFIRMING IN PART, VACATING IN PART, AND
REVERSING IN PART, INITIAL DECISION

APPEARANCES

Gary A. Morgans, Bruce J. Barnard, Michael D. Mackness, Jennifer Key, and Edward Twomey for Southern California Edison Company;

Bonnie S. Blair for Cities of Anaheim, Azusa, Banning, Colten and Riverside, California;

Alan I. Robbins, Elisa J. Grammar, and Mark D. Urban for California Department of Water Resources;

Arnold Fieldman, Channing D. Strother, and David B. Brearley for the City of Vernon;

Harvey Y. Morris and Peter Arth, Jr., for Public Utilities Commission of the State of California;

Edward Berlin, David Ruben, and Michael Ward for California Independent System Operator Corporation;

Lisa G. Dowden and Sarah Weinberg for Northern California Power Agency;

Mark D. Parizio for Pacific Gas and Electric Company;

Michael Yuffee and Joel Newton for Sacramento Municipal Utility District;

James D. Pembroke, Wallace L. Duncan, Michael Postar, Lisa Gast, and Diana Mahmud for Transmission Agency of Northern California, The Metropolitan Water District of Southern California, Modesto Irrigation District, City of Santa Clara, California City of Redding, California, M-S-R Public Power Agency, and Trinity County Public Utility District; and

Linda Lee, Stanley A. Berman, Jo Ann Scott, Janet Jones, Laura K. Sheppeard, and Richard L. Miles for the trial staff of the Federal Energy Regulatory Commission

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert, Jr

Southern California Edison Company

Docket Nos. ER97-2355-000, ER98-1261-000, and ER98-1685-000

OPINION NO.445

OPINION AND ORDER
AFFIRMING IN PART, VACATING IN PART, AND
REVERSING IN PART, INITIAL DECISION

(Issued July 26, 2000)

I. Introduction

This case is before the Commission on exceptions to an Initial Decision issued March 31, 1999.[1] For the reasons set forth below, we will affirm in part, vacate in part, and reverse in part, the Initial Decision.

II. Procedural Background

On March 31, 1997, Southern California Edison Company (SoCal Edison) filed, in Docket No. ER97-2355-000, a Transmission Owner (TO) Tariff, for utility-specific rates to be charged for transmission service on its facilities under the operational control of the California Independent System Operator (California ISO). In the same filing, SoCal Edison also submitted a Distribution Access (DA) Tariff for transmission service over its distribution facilities that are not part of the California ISO grid. In an order issued by

[1]Southern California Edison Company, 86 FERC ¶ 63,014 (1999) (Initial Decision).

the Commission on December 17, 1997,[2] we accepted SoCal Edison's TO and DA Tariffs, for filing, suspended them, and permitted them to become effective, subject to refund, on the date the California ISO began operation. We also set the proposed tariffs for hearing.

On December 31, 1997, SoCal Edison filed, in Docket No. ER98-1261-000, proposed revisions to its TO Tariff to add a surcharge of $.00009/kWh for a one-year period, to recover $6.7 million in costs associated with its abandoned Devers-Palo Verde 2 project. On January 29, 1998, SoCal Edison filed, in Docket No. ER98-1685-000, proposed revisions to its TO Tariff to correct what it claimed were computational errors and omissions in the development of the rates set for hearing in the December 17 Order. In separate orders issued by the Commission on February 25, 1998,[3] and March 30, 1998,[4] we set SoCal Edison's proposed tariff revisions for hearing and consolidated these filings with SoCal Edison's pending proceeding in Docket No. ER97-2355-000.[5]

Prior to hearing, a number of issues initially set for hearing were resolved. First, the rate-effective period applicable to SoCal Edison's proposed cost-based rates for ancillary services was narrowed by the Commission's ruling in Docket No. ER98-2843-001, in which we granted market-based rate authority to all entities providing ancillary services in California, effective November 3, 1998.[6] As such, SoCal Edison's proposed cost-based rates for ancillary services is this proceeding are only for a locked-in period, April 1, 1998 through November 2, 1998. In addition, the parties filed a stipulation with

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[2]Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,323 (1997) (December 17 Order), order on reh'g, 82 FERC ¶ 61,324 (1998).

[3]California Independent System Operator Corporation, et al., 82 FERC ¶ 61,174 (1998).

[4]San Diego Gas & Electric Company, et al., 82 FERC ¶ 61,324 (1998).

[5]On February 6, 1998, the Chief Administrative Law Judge severed issues concerning non-rate terms and conditions from rate issues, and assigned the SoCal Edison's TO Tariff and DA Tariff filing to the Presiding Judge. See Pacific Gas & Electric Company, et al., 82 FERC ¶ 63,010 (1998).

[6]AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998) (AES).

the Presiding Judge, which the Presiding Judge accepted, fully resolving six issues originally set for hearing. [7]

An evidentiary hearing on all remaining issues commenced on September 15, 1998 Following the hearing and the filing of initial and reply briefs, the Presiding Judge issued the Initial Decision. Briefs on exceptions were filed by SoCal Edison, the Commission's trial staff (trial staff), the California ISO, the Department of Water Resources of the State of California (DWR). Briefs opposing exceptions were filed by SoCal Edison, trial staff, DWR, the Northern California Power Agency (NCPA), the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (Cities), the Public Utilities Commission of the State of California (California Commission), and the City of Vernon (Vernon).

IV. Discussion

A. Issues Identified and Resolved by the Initial Decision

The Initial Decision identified and resolved 17 issues. Of these issues, we will summarily affirm Issue Nos. 1-3, 5, 8, 11-12, 14-15, and 17; and vacate as moot Issue Nos. 9-10, and 13, in part. The remaining issues (Issue Nos. 4, 6-7, 13, and 16) are discussed below.

B. Summary Affirmance Issues

No party excepted to the Presiding Judge's disposition of Issues Nos. 1-3, 5, 14-15, and 17. Specifically, the Presiding Judge ruled (and no party now contests) that: (1) SoCal Edison's reliance on a 45-day cash working capital allowance in rate base is reasonable, subject to the adjustments discussed elsewhere in the Initial Decision (Issue No. 1); (2) SoCal Edison's claimed rate base for plant held for future use, Account 105, (Issue No. 2), [8] and for construction work in progress, Account 107, (Issue No. 3), should be addressed in a compliance filing to be made by SoCal Edison to demonstrate that SoCal Edison's Account 105 and Account 107 costs do not recover costs already included

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[7] Initial Decision, 86 FERC at 65,136 (citing the following issues: abandoned plant; rate base adjustments; South Georgia adjustments; depreciation; revenue credits for wholesale transmission and power sales agreements; and the divisor for wholesale and access charges).

[8] Our ruling includes the requirement that SoCal Edison's compliance filing must demonstrate that such plant is not also recorded in Account 101.

in Account 101, electric plant in service; (3) the California Commission's proposal for the disposition of refunds to retail customers should be followed, in the event a lower transmission revenue requirement than that proposed by SoCal Edison is found just and reasonable (Issue No. 5); (4) the term of the TO Tariff may be superceded by the new California ISO Tariff, but in any event, does not need not be addressed in this proceeding (Issue No 14); (5) SoCal Edison's load dispatching expenses included in Account 561 are incurred by SoCal Edison for the benefit of all users of the transmission system and should therefore be allowed, as claimed (Issue No. 15); and (6) Vernon's proposal allowing ratepayers to recover a share of the gains realized by SoCal Edison from the sale of its oil and gas generating plants was not supported and should be rejected (Issue No. 17).

We find that the Presiding Judge's rulings on these issues were well reasoned and fully supported by the record. Accordingly, these rulings are hereby summarily affirmed. We also summarily affirm the ruling of the Presiding Judge: (1) accepting rolled-in rates for the TO Tariff wholesale access charge (Issue No. 8); (2) rejecting the proposal for time-of-use transmission rates (Issue No. 11); and (3) accepting the DA Tariff rate design (Issue No. 12). We find that the Initial Decision properly decided these issues on the grounds set forth in the Initial Decision. We therefore deny the exceptions on these issues asserted by SoCal Edison (as to Issue No. 8) and DWR (as to Issue Nos. 11-12).

C. Vacated Issues

We will vacate the Initial Decision as to those issues concerning membership rights and incentives to join the California ISO (Issue Nos. 9, 10, and 13).[9] On March 31, 2000, in Docket No. ER00-2019-000, the California ISO filed Amendment No. 27 to its tariff to address these issues. Amendment No. 27 proposes a new methodology for recovering, through a Transmission Access Charge (TAC), the embedded cost of transmission facilities comprising the Califiornia ISO-controlled grid. In our order issued May 31, 2000, we accepted for filing, suspended, and set for hearing the proposed TAC methodology and related tariff revisions.[10] Given these changed circumstances, the issues litigated in this proceeding relating to parties joining the California ISO are rendered moot. Therefore, we will vacate the Initial Decision

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[9]These incentives include, among other things, removal of the self-sufficiency test, which in turn eliminates the Non-Self Sufficiency Access charge.

[10]See California Independent System Operator Corp., 91 FERC 61,205 (2000). We also held the hearing in abeyance pending efforts at settlement and established settlement judge procedures.

regarding these issues, specifically, the appropriate billing determinants to be used for SoCal Edison's Non-Self Sufficient Access charge (Issue No. 9), whether a monthly versus an hourly rate should be used for SoCal Edison's Non-Self Sufficient Access charge (Issue No. 10), and all issues relating to customer credits for participating transmission owners (Participating TOs) (Issue No. 13).[11]

D. Whether the Presiding Judge Properly Determined that Non-Participating TOs Should Receive Credits for their Customer-Owned Transmission Facilities

Initial Decision

At hearing, Vernon and Cities (collectively Municipals) argued that as non-Participating TOs they should receive network customer credits against their Access Charges for their transmission facilities that are integrated with SoCal Edison's transmission system. Prior to restructuring, the creation of the California ISO, and SoCal Edison's filing of its TO Tariff, the Municipals were receiving an implicit credit for their customer-owned transmission facilities under their Intergrated Operating Agreements (IOAs) through hub and spoke pricing. In late 1996 and early 1997, as a result of the California restructuring process, the parties negotiated Restructuring Agreements, creating the current Transmission Service Agreements (TSAs), and terminated the IOAs. Under the TSAs, Municipals still pay for transmission solely within SoCal Edison's 230 kV hub network and not for SoCal Edison's spokes which generally parallel Municipals' transmission facilities. At hearing, Municipals argued that after their TSAs expire it will be unfair to take service under the TO Tariff using rolled-in pricing.[12]

SoCal Edison, the California ISO, and trial staff disagreed, relying on Florida Municipal Power Agency v. Florida Power & Light Company[13] and Orders Nos. 888 and 888-A. These parties argued that the Municipals' facilities are not integrated with the California ISO-controlled grid, which now includes SoCal Edison's transmission facilities, and therefore network customer credits should be denied. They further argued

[11]That portion of Issue No. 13 which addresses credits for non-participating TO's has not been rendered moot. The exceptions raised with respect to this issue, therefore, are addressed below.

[12] The TSA expiration dates differ for each agreement, with some TSAs terminating as early as December 31, 2002.

[13] 67 FERC ¶ 61,167 (1994) (FMPA), reh'g denied, 74 FERC ¶ 61,006 (1996).

that the only relevant test for integration under the restructured California ISO framework is if the California ISO has operational control and scheduling rights for the use of the transmission facilities.

The Presiding Judge rejected these arguments and found that the Municipals' facilities provide substantial support to the California ISO-controlled grid and that the Municipals act functionally as network service customers, meeting the Commission's requirements for network customer credits. On the matter of whether the Municipals should receive a network customer credit as Non-Participating TOs, the Presiding Judge found that the elimination of the implicit credits with the expiration of the TSAs would be unjust and unreasonable. The Presiding Judge ruled that SoCal Edison must modify the proposed wholesale wheeling access charge to permit the Municipals to pay hub-only costs instead of rolled-in costs once their TSAs expire.

Exceptions

SoCal Edison, the California ISO and trial staff filed exceptions. SoCal Edison and trial staff argue that the rates and term of the TSAs were the result of negotiation by the affected parties for the purpose of implementing restructuring, and that the Initial Decision has the effect of improperly extending these existing agreements beyond their negotiated contract terms. SoCal Edison also argues that the Presiding Judge's ruling on this issue undermines the ruling accepting rolled-in rates by making exceptions for the Municipals. Finally, SoCal Edison contends that the continuation of the TSAs beyond their negotiated terms unduly discriminates against the other users of the transmission system, including SoCal Edison's retail customers, who will have to pay higher rates when the current TSAs expire for the same service. [14]

The California ISO adds that because no party to this proceeding proposed continuation of the sub-functional (hub and spoke) rates, they were not a subject of discussion during the hearing, and there is no record evidence of the impact of such rates on other market participants. The California ISO concludes that under these circumstances, the justness and reasonableness of these rates was unsupported.

Cities and Vernon oppose these exceptions. Cities states that the Initial Decision does not extend the Cities' current contract rights, nor does the Initial Decision rely on the TSAs in reaching the conclusion that credits for the Municipals are appropriate. Cities argue that the Presiding Judge's findings were based on proper ratemaking principles and are independent of the contractual arrangements embodied in the TSAs and Restructuring

[14] SoCal Edison's Brief on Exceptions, at pp. 62-65.

Agreements. Vernon adds that SoCal Edison has proposed a new rate methodology in this proceeding which the Presiding Judge modified to grant customer credits. Vernon also disagrees with the assertions made by SoCal Edison and trial staff that the Presiding Judge has extended the existing contracts beyond their negotiated term, stating that the Presiding Judge's determination has only modified the proposed rates to incorporate the previous TSA's sub-functional rates.

Discussion

Although we have vacated the issue of customer credits for Participating TOs due to the ISO's TAC filing, in Docket No. ER00-2019-000, specifically the proposal to eliminate the non-self sufficiency test, [15] we will discuss here the issue of customer credits for non-Participating TOs.

FMPA, Order No. 888, and Order 888-A, all require that for facilities to be considered integrated, the transmission provider must be able to provide transmission service to itself or other transmission customers over these facilities As of the start-up of the California ISO, SoCal Edison no longer served as the transmission provider. Under these circumstances, until and unless the Municipals join the California ISO and turn over control of their facilities to the California ISO, the California ISO can have no operational control over Municipals' facilities. If the California ISO has no operational control over these facilities, it can not use them to provide transmission service to its customers. In fact, the California ISO would not even be able to transmit power over the customer facilities to the Municipals.

The Presiding Judge's ruling gives the benefit of California ISO membership without assigning any corresponding responsibilities to the Municipals. The result of this ruling is that other users of the California ISO grid would pay for the implicit credit, but would not be able to use the facilities. In addition, the Presiding Judge's ruling would require the rolled-in rate for other users to be modified each time a TSA expires, creating a lack of uniformity in rates over several years. In order for the Municipals to receive credits for their facilities, they must join the California ISO and thereby allow scheduling and control of the facilities by the transmission provider.

In addition, we find that the Presiding Judge improperly applied the terms and conditions of a negotiated contract to the proposed wholesale wheeling access charge. As noted by Cities' witness, the parties "mutually agreed in the Restructuring Agreements to terms and conditions under which the IOAs would terminate and the Cities will make the

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[15] See section C supra.

transition to independent operation in the restructured market". [16] The terms and conditions of the Restructuring Agreements were negotiated as a package with the expectation that the Municipals would eventually be able to operate independently. The Presiding Judge's ruling acts to sever the expiration term of the contract from the other terms and conditions mutually agreed upon by the parties, and would have the effect of abrogating the parties' agreement, without a reasonable basis for doing so. Therefore, we reverse the Presiding Judge's ruling that the implicit credit contained in the TSA's should be continued in the wholesale wheeling access charge.

E. Whether the Presiding Judge Properly Determined SoCal Edison's Rate of Return on Common Equity

Initial Decision

The Initial Decision declined to adopt the rate of return on common equity (ROE) proposed by SoCal Edison (11.6 percent) or trial staff (8.71 percent). The Initial Decision also accepted, in part, and rejected, in part, the methodologies used by these parties for calculating their respective ROEs. Based on the Presiding Judge's application of a two-stage discounted cash flow (DCF) formula which the Presiding Judge found to be consistent with the Commission's recent precedents in natural gas pipeline company cases, [17] the Presiding Judge calculated an ROE for SoCal Edison of 9.68 percent.

The Initial Decision found that the ROE recommendations made by SoCal Edison and trial staff differed significantly, due to the differing methodologies advanced by these parties to calculate SoCal Edison's ROE. These differences included: (1) trial staff's stand alone analysis of SoCal Edison versus SoCal Edison's analysis of a proxy group; (2) trial staff's use of a DCF analysis alone versus SoCal Edison's reliance on a DCF/risk premium analysis; (3) SoCal Edison's reliance on the gross domestic product (GDP) for the long-term growth factor in the DCF analysis versus trial staff's use of DRI industry data; and (4) the use or rejection of adjustments based on flotation costs and risk assessments.

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[16] Vernon's Brief Opposing Exceptions, at pp. 43-44.

[17] Initial Decision, 86 FERC at 65,143, citing Williston Basin Interstate Pipeline Company, 50 FERC ¶ 61,284 (1990) (Williston), vacated on other grounds, 931 F.2d 948 (D.C. Cir. 1991); Northwest Pipeline Corporation, 79 FERC ¶ 61,309 (Opinion No. 396-B), reh'g denied, 81 FERC ¶ 61,036 (1997) (Opinion No. 396-C); and Transcontinental Gas Pipe Line Corporation, 80 FERC ¶ 61,157 (1997) (Opinion No. 414), reh'g, 84 FERC ¶ 61,084 (1998) (Opinion No. 414-A).

The Presiding Judge concluded that in performing the DCF analysis in this case, the proxy group advanced by trial staff was appropriate because it is the Commission's preferred approach for natural gas pipeline companies and because "[t]he same logic should apply to electric companies."[18] The Presiding Judge also held that a DCF analysis rather than a risk premium analysis, or a combination thereof, was appropriate because, among other reasons, it was consistent with Commission policy. In addition, the Presiding Judge accepted the use of the Institutional Brokers Estimation System (IBES) growth projections for the short-term growth factor in the DCF model and held that SoCal Edison's recommended use of GDP data, as a long-term growth factor, was appropriate because it was consistent with the Commission's rulings in Williston and Opinion No. 396-B.[19] Finally, the Presiding Judge chose the median return from the zone of reasonableness of the proxy group of companies he relied on to calculate his ROE, without an adjustment for flotation costs, based on his assessment of SoCal Edison's business and financial risks.

Exceptions

Exceptions were filed by SoCal Edison and trial staff. SoCal Edison argues that the Presiding Judge's ROE of 9.68 percent "fails to reflect the significant risks that [SoCal Edison] faces in the restructured electric utility environment, and reduces [SoCal Edison's] ROE substantially below levels previously allowed by the [California Commission] on the same assets for the same service."[20] SoCal Edison also claims that in addition to the DCF model, use of a risk premium analysis is appropriate because: (1) it is widely used and relied upon; and (2) the bond yields, on which the analysis is based, reflect investors' perceptions on a forward-looking basis.

SoCal Edison also objects to the Presiding Judge's rejection of its proxy group. SoCal Edison states that the companies included in trial staff's proxy group, which the Presiding Judge relied upon, have a lower risk profile than SoCal Edison. SoCal Edison also takes issue with the Presiding Judge's reliance on the Commission's natural gas pipeline precedents for the weighting to be given the short and long-term dividend growth rates, as used in the DCF formula to calculate "g." While in these precedents, the

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[18]Id. at 65,141.

[19]The Presiding Judge also determined that the short-term growth component should be given a two-thirds weight, and the long-term component a one-third weight, consistent with the Commission's recent natural gas pipeline company cases.

[20]SoCal Edison's Brief on Exceptions, at 7.

Commission gave a two-thirds weighting to short-term growth and a one third weighting to long-term growth, SoCal Edison claims that the Presiding Judge failed to explain why this same weighting would be appropriate in the case of an electric utility.

Trial staff asserts as error the Presiding Judge's decision not to use the long-range growth forecast of the electric industry's return on total capital, as published by Data Resources Inc. (DRI), for the long-term projection of growth in the DCF model. Trial staff also asserts as error the Presiding Judge's failure to consider company-specific data in the form of a stand-alone DCF in determining SoCal Edison's ROE.

Order Establishing Further Procedures

On September 17, 1999, the Commission issued an "Order Establishing Further Procedures On Issue Of Rate of Return on Common Equity." [21] In the September 17 Order, the Commission held that it would be in the public interest to consider additional arguments in this proceeding on the issue of SoCal Edison's ROE "[i]n light of the possible risks associated with the transfer of operational control of facilities to the California ISO, and the potential increase, since the end of the hearing, in the number of public utilities that face similar risks. . . ." The September 17 Order permitted interested parties to file initial and reply comments on these issues. [22]

Initial Comments

Initial Comments were timely filed by the California Electricity Oversight Board (Board); trial staff; the California Commission; the Sacramento Municipal Utility District (SMUD); and SoCal Edison. In addition, a motion for leave to file initial comments one day out of time was filed by Pacific Gas and Electric Company (PG&E), and motions for late intervention and comments were filed by Edison Electric Institute (EEI), the Electricity Consumers Resources Council (ELCON) and the American Iron and Steel Institute (AISI); and the Midwest ISO Participants (ISO Particpants). [23]

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[21] Southern California Edison Company, 88 FERC ¶ 61,254 (1999) (September 17 Order).

[22] As required by the September 17 Order, Initial Comments were filed on November 1, 1999. Reply Comments were filed December 1, 1999.

[23] Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2000), we will grant the unopposed motions to intervene filed by EEI,
(continued...)

SoCal Edison submits an updated ROE analysis, in its comments, in which it updates both its DCF study as well as its two risk premium analyses. These updated analyses are based on data for the period April 1999 through September 1999 and support, in SoCal Edison's view, an ROE in this case of at least 11.6 percent. SoCal Edison explains that this recommended ROE is based on the high end of the zone of reasonableness indicated by SoCal Edison's DCF analysis and is supported by a finding that SoCal Edison faces significant risks attributable to its joining the California ISO.

In assessing the risks it faces, SoCal Edison asserts that other industries that have experienced similar unbundling and partial deregulation should be studied, including the telecommunications and natural gas pipeline industries. SoCal Edison states that in these industries, there is clear evidence that unbundling one component of a previously integrated company can increase the risk attributable to the other components of the company's business. SoCal Edison also argues that in setting its ROE in this case, the Commission should consider the broader policy issue it discussed in the RTO proceeding, i.e., the option of using ROEs to give electric utilities an incentive to make investments in new transmission facilities.

ISO Participants, PG&E, and EEI argue that higher ROEs for the electric utility industry as a whole are necessary because in the restructured market, electric utilities face an increased risk of non-recovery of their transmission revenue requirements. EEI points out that while higher ROEs may mean higher direct costs for consumers, it will mean an avoidance of the far more significant indirect costs that could be incurred if utilities are not given the proper incentives to participate fully in the restructured market. ISO Participants add that the DCF analyses of integrated electric utilities may not reflect the risks associated with RTOs because the earnings growth forecasts for vertically integrated companies do not reflect transmission-only growth forecasts, nor do they reflect the increased financial and operational risks associated with joining an RTO. PG&E asserts that there are significant regulatory risks associated with a transfer of jurisdiction from the California Commission to the Commission, and that an exclusive reliance on a DCF analysis using electric utilities as a proxy group significantly understates the risks that SoCal Edison faces, because the electric utilities that comprise this proxy group are undergoing so much change at the present time.

Trial staff, the California Commission, the Board, ELCON, and AISI assert a different position on these issues. Trial staff argues that there is no evidence that SoCal

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[23](...continued)
ELCON, AISI, and the ISO Participants. We will also accept the initial comments filed one day out of time by PG&E.

Edison has become exposed to any new risks following the close of the record in this case, and suggests that SoCal will fully recover its stranded generation costs and plans to make significant new generation investments. Trial staff also cites evidence that the stock value of SoCal Edison's parent has and will continue to out-perform the electric utility averages. In addition, trial staff states that SoCal Edison itself has performed well since the advent of retail unbundling and intends to make substantial investments in its transmission and distribution network [24]

The California Commission and the Board state that any increased risks facing SoCal Edison as a result of its participation in the California ISO were fully addressed by the California legislature in Assembly Bill 1890 (AB 1890), and that SoCal Edison retains the right to file section 205 rate cases at the Commission to recover its transmission revenue requirements.

ELCON, AISI and SMUD agree with the general thrust of these arguments. They argue that SoCal Edison's risks have been significantly reduced since its restructuring, and that its credit rating will actually improve as a result of its membership in the ISO, given its ability to recover its stranded costs. However, because an immediate reduction in ROEs for other utilities may act as a disincentive to their membership in RTOs, ELCON and AISI support the allowance of a grace period, during which utilities joining RTOs will be permitted to retain their current ROEs. SMUD argues that an artificially-inflated ROE is contrary to sound, cost-based ratemaking practices, and believes that SoCal Edison does not have increased risk associated with its participation in the California ISO.

Reply Comments

Reply comments were timely filed by ELCON; SoCal Edison; SMUD; the Metropolitan Water District of Southern California (Metropolitan); the California Commission; and trial staff. Trial staff and SMUD note, in their reply comments, that many of the arguments raised by SoCal Edison and others, in support of raising SoCal Edison's ROE in this case, address issues which have no bearing on the issues identified by the Commission in the September 17 Order. Trial staff further points out that other

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[24] Trial staff does note, however, that following the close of the record in this case, changes in the financial markets have occurred, which would justify an increased ROE for SoCal Edison over the figure advanced by trial staff at hearing. Specifically, the 8.71 percent return initially recommended by trial staff should be adjusted upward to 9.47 percent, based on the updated data on which trial staff relies and the same methodology previously utilized by trial staff's witness.

issues raised by these parties may have a bearing on other utilities or other industries, but have not been shown to have a bearing on the electricity market in California, or on SoCal Edison, specifically. Trial staff also takes issue with SoCal Edison's argument that the California ISO has no financial incentive in maximizing the company's profits. Trial staff claims that this risk, if it existed, would already be reflected in investors' expectations. Metropolitan also asserts that this risk is overstated and that it overlooks the many benefits conferred upon SoCal Edison as a result of its membership in the California ISO.

The California Commission also disputes SoCal Edison's claim that it risks less growth in its regulated business. The California Commission notes that SoCal Edison's own president has forecasted a substantial growth in its service territory. The California Commission also disputes SoCal Edison's claim that a higher ROE is necessary in order to further expand the transmission grid, pointing to other cases approving lower ROEs for utilities who are nonetheless pursuing expansion projects.

In its reply comments, Metropolitan urges the Commission to set SoCal Edison's ROE in this case based solely on SoCal Edison's electric transmission business. Metropolitan also urges the Commission not to use the instant proceeding to announce any new policies regarding appropriate ROEs for utilities who voluntary join an RTO pursuant to Order No. 2000. Metropolitan points out that because the California ISO was not voluntarily established, it does not fit the new paradigm contemplated by Order No. 2000. SMUD concurs with Metropolitan on this point.

ELCON takes issue with EEI's conclusion that restructuring will enhance the risk faced by transmission owners. ELCON asserts, to the contrary, that restructured transmission services, because they will be regulated, will continue to qualify for a fair ROE. ELCON also states that in a restructured environment, transmission owners will no longer be burdened by the substantial risks associated with generation.

SoCal Edison's reply comments take issue with the contention that it is seeking a premium ROE as a reward for its having joined the California ISO. SoCal Edison argues that the ROE it is seeking is fully commenserate with the risks it faces. SoCal Edison also takes issue with those comments addressing such issues as retail restructuring, generation, distribution and stranded cost recovery. SoCal Edison asserts that the issue for review, pursuant to the September 17 Order, are not these issues, but the risk that California ISO membership imposes on SoCal Edison's transmission business.

Discussion

The record in this proceeding was reopened for the purpose of considering additional evidence and arguments on ROE. As noted above, numerous comments were received, including the submission of revised DCF analyses by SoCal Edison and trial staff, and new DCF analyses submitted by SMUD and PG&E. These parties developed their ROE recommendations using either a DCF or a risk premium analysis or a combination of the two. The DCF analyses submitted in the supplemental record are similar to both the DCF analyses submitted by SoCal Edison and trial staff in the original proceeding and the DCF analysis adopted by the Presiding Judge. Each of these analyses relies on a weighted averaging of a short-term and a long-term growth rate, and purports to comply with the Commission's two-step DCF methodology, as set forth in Opinion No. 396-B.

The Commission, to date, has not expressly addressed the differing approaches taken in setting ROEs for gas pipelines and for electric utilities. This proceeding, however, presents the Commission with its first opportunity to calculate an ROE for an electric utility company where the positions advocated by the parties, and the record evidence contains both short-term and long-term growth data, consistent with our latest formulation of a two-step DCF methodology for natural gas pipeline companies. [25] The issue presented here, therefore, is whether the Commission's preferred DCF methodology for natural gas pipeline companies should be applied, without variation, to an electric utility company, in place of the Commission's standard, constant growth DCF model, previously relied upon by the Commission in calculating an ROE for an electric utility company. [26]

As noted above, the Presiding Judge applied the two-step DCF model currently used by the Commission in natural gas pipeline cases, reasoning, among other things, that

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[25]See, e.g., note 10 supra. The Commission's preferred approach in both gas pipeline and electric utility proceedings, is to use a DCF methodology to calculate the ROE. As discussed below, however, the two policies have diverged in how they determine the appropriate growth rate used in the DCF model.

[26]See, e.g., Southern California Edison Company, 56 FERC ¶ 61,003 (Opinion No. 362), order on reh'g, 56 FERC ¶ 61,117 (1991) (Opinion No. 362-A); Connecticut Light & Power Co., 43 FERC ¶ 61,508 (1988), Jersey Central Power & Light Co., 77 FERC ¶ 61, 001 (1996), Southwestern Public Service Co., 83 FERC ¶ 61,138 (1998), Appalachian Power Co., 83 FERC ¶ 61,335 (1998) (Appalachian), and Consumers Energy Co., 85 FERC ¶ 61,100 (1998).