Energy
Industry Research



Electric Utilities Quarterly 1Q10

**Solid 1Q Earnings Mostly Aided by Favorable Weather,
Modest Signs of Economic Stabilization**

**Near Term, We Believe the Sector Exhibits Increased Regulatory Risk
Buffered by Stable Yields**

**Long Term, We Believe the Sector Is Poised for
a Return to Earnings Growth with Economic Recovery**

June 2010

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KeyBanc Capital Markets

For important disclosures and certifications, please refer to page 59 of this document.

**KeyBanc Capital Markets Inc.,
Member NYSE/FINRA/SIPC**

Contents

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INDUSTRY UPDATE

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1Q10 RESULTS — BY THE NUMBERS

EARNINGS COMPARISON

Overall, companies within our electric utilities coverage universe generally reported better than anticipated 1Q10 results, aided primarily by favorable weather and modest signals of the U.S. economy stabilizing from improving industrial sales. Aggregate earnings for stocks in the KeyBanc Capital Markets Electric Utility Index were up 8.0% on average compared to the same quarter a year ago, as indicated in Table 1. Based on our estimates, we had initially anticipated a modest 0.5% uptick in quarterly earnings.

Table 1. Earnings Comparison

Company	Ticker	1Q10E	1Q10A	1Q09A	1Q Change	2010E	2011E
Ameren Corp.	AEE	$0.38	$0.40	$0.54	(25.9)%	$2.25	$2.30
American Electric Power, Inc.	AEP	$0.75	$0.76	$0.89	(14.6)%	$3.05	$3.20
Avista Corp.	AVA	$0.56	$0.52	$0.57	(8.8)%	$1.55	$1.80
CMS Energy, Inc.	CMS	$0.37	$0.38	$0.30	26.7%	$1.35	$1.45
Central Vermont Public Service Corp.	CV	$0.38	$0.35	$0.58	(39.7)%	$1.60	$1.70
Cleco Corp. [a]	CNL	$0.45	$0.55	$0.18	205.6%	$2.15	$2.20
Consolidated Edison, Inc	ED	$0.80	$0.93	$0.78	19.2%	$3.25	$3.45
DPL Inc. [b]	DPL	$0.59	$0.59	$0.53	11.3%	$2.40	$2.45
DTE Energy Co.	DTE	$1.30	$1.38	$1.10	25.5%	$3.60	$3.75
Dominion Resources, Inc.	D	$0.93	$0.96	$0.97	(1.0)%	$3.30	$3.25
Duke Energy Corp.	DUK	$0.32	$0.36	$0.28	28.6%	$1.30	$1.35
Entergy Corp.	ETR	$1.11	$1.33	$1.29	3.1%	$6.75	$6.90
Exelon Corp	EXC	$0.89	$1.00	$1.20	(16.7)%	$3.85	$4.00
FPL Group, Inc.	FPL	$0.88	$0.94	$0.90	4.4%	$4.35	$4.45
FirstEnergy Corp	FE	$0.74	$0.81	$1.01	(19.8)%	$3.65	$3.75
Great Plains Energy, Inc.[c]	GXP	$0.10	$0.15	$0.04	275.0%	$1.35	$1.65
IDACORP, Inc.	IDA	$0.39	$0.34	$0.44	(22.7)%	$2.75	$2.80
MDU Resources Group, Inc.	MDU	$0.28	$0.22	$0.22	N/M	$1.45	$1.60
NiSource, Inc.	NI	$0.70	$0.72	$0.63	14.3%	$1.15	$1.20
Northwestern Corp. [d]	NWE	$0.76	$0.70	$0.68	2.9%	$1.85	$2.25
PPL Corp.	PPL	$0.92	$0.94	$0.60	56.7%	$3.25	$3.15
Pepco Holdings, Inc.	POM	$0.17	$0.16	$0.17	(5.9)%	$0.90	$1.20
Pinnacle West Capital Corp.[e]	PNW	$0.00	$0.07	($0.25)	128.0%	$3.00	$3.05
Progress Energy, Inc.	PGN	$0.69	$0.75	$0.66	13.6%	$3.00	$3.10
Southern Company	SO	$0.45	$0.60	$0.42	42.9%	$2.40	$2.50
TECO Energy, Inc.	TE	$0.27	$0.34	$0.14	142.9%	$1.30	$1.40
Wisconsin Energy Corp.	WEC	$0.98	$1.10	$1.20	(8.3)%	$3.75	$4.10
Xcel Energy Inc.	XEL	$0.37	$0.42	$0.38	10.5%	$1.60	$1.70
Average					**8.0%**		

a) CNL's 1Q09A EPS of $0.18 excludes $0.07 of gains from interim period income tax adjustments we consider a special item ($0.11 reported).
b) DPL's 1Q09A EPS of $0.53 excludes $0.08 of gains attributable to deferrals of RTO related costs from prior years ($0.61 reported).
c) GXP earnings and estimates reported as GAAP net income.
d) NWE's ongoing 1Q09A EPS of $0.68 excludes $0.05 insurance reserves charges we consider to be non-recurring ($0.63 reported).
e) We treat PNW's sale of a majority of SunCor real estate assets as discontinued operations and exclude the real estate segment from our results and estimates.
Source: Company data, KeyBanc Capital Markets Inc.

EARNINGS SURPRISES

On an individual company basis, there were plenty of notable upside surprises and one notable downside surprise relative to our expectations for the quarter. On the upside, Cleco Corporation (CNL-NYSE; $0.55 vs. $0.18 in 1Q09; our estimate was $0.45, First Call consensus was $0.33) beat our high on the Street estimate primarily due to favorable cold weather, higher rates and tax timing benefits. Consolidated Edison, Inc. (ED-NYSE; $0.93 vs. $0.78 in 1Q09; our estimate was $0.80, First Call consensus was $0.81) reported better than expected results as higher earnings from the Company's electric, gas and steam rate plans were partly offset by higher operating and maintenance, depreciation, property tax and interest expenses. Southern Company (SO-NYSE; $0.60 vs. $0.42 in 1Q09; our estimate was $0.45, First Call consensus was $0.44) and TECO Energy, Inc. (TE-NYSE; $0.34 vs. $0.14 in 1Q09; our estimate was $0.27, First Call consensus was $0.25) both beat expectations on favorable cold winter weather and modest signs of a slow economic recovery. Wisconsin Energy Corporation (WEC-NYSE; $1.10 vs. $1.20 in 1Q09; our estimate was $0.98, First Call consensus was $1.02) surprised and beat our estimate to the upside due to higher retail pricing, lower depreciation and the absence of prior-year MISO RTO-related bill credits, despite quarterly earnings being lower due to fuel under-recoveries, higher operating and maintenance costs, and mild weather.

On the downside, earnings at IDACORP, Inc. (IDA-NYSE; $0.34 vs. $0.44 in 1Q09; our estimate was $0.39, First Call consensus was $0.41) came in below our low on the Street estimate due to mild weather and continued economic weakness in its service territory.

As highlighted in our quarterly earnings preview, we correctly called both 1Q10 upside surprises for DTE Energy Company (DTE-NYSE; $1.38 vs. $1.10 in 1Q09; our estimate was $1.30, First Call consensus was $1.20) and NiSource, Inc. (NI-NYSE; $0.72 vs. $0.63 in 1Q09; our estimate was $0.70, First Call consensus was $0.68) primarily from improving industrial demand. In addition to aforementioned IDACORP Inc., we also correctly forecast American Electric Power Company, Inc. (AEP-NYSE; $0.76 vs. $0.89; our estimate was $0.75, First Call consensus was $0.78) results to come in as a downside surprise in a difficult economy.

EARNINGS ADJUSTMENTS

Heading into 1Q10 earnings reporting season, we raised our 2010 estimate for NiSource to $1.15 from $1.10 per share for a modestly improving economy in Indiana (industrial and residential demand). We raised our 2010 estimate for Cleco (CNL-NYSE) to $2.15 from $2.10 per share on reports of favorable winter weather in the Southeast. We lowered our 2010 estimate for DPL Inc. (DPL-NYSE) to $2.40 from $2.50 per share due to weaker power prices and wholesale opportunities for the Company. We also reduced our 2010 estimate for Pepco Holdings, Inc. (POM-NYSE) to $1.00 from $1.35 per share to remove gross margins and earnings associated with the wind-down of unregulated merchant operations.

Following quarterly earnings reports, earnings conference calls and investor/analyst meetings, we further revised some earnings estimates. We subsequently reduced our 2010 Pepco estimate further down to $0.90 from $1.00 per share after the Company initiated earnings guidance at $0.80-$0.95 per share, indicating 2010 would be a "transition year" due to the planned sale of its merchant generation facilities in its Conectiv Energy segment. We also lowered our 2010 estimate for Avista Corporation (AVA-NYSE) to $1.55 from $1.70 per share as poor hydro conditions and mild weather impacted the quarter. We raised our 2010 estimate for DTE Energy to $3.60 from $3.50 per share for improving electric margins and load trends, cost savings and 1Q strength in Power & Industrial Projects and Energy Trading segment results. Finally, we raised our 2010 Southern Company estimate to $2.40 from $2.35 per share for solid 1Q results and positive economic signs in its region, particularly in the industrial sector.

Additionally, as shown in Table 1, we have introduced our 2011 earnings estimates for companies under coverage.

STOCK PRICE PERFORMANCE

As shown in Table 2, stock price performance during 1Q10 for companies under coverage in the KeyBanc Capital Markets Electric Utility Index was negative, with the quarter showing an average stock price decrease of 2.8%. Stock returns were challenged by some of the larger-cap, more commodity-oriented names with merchant generation exposure. Our coverage group's performance was better than the Philadelphia Utility Index (UTY), which lost 4.5% in 1Q10, but underperformed the broader S&P 500 Index (SPX), which increased 4.9% for the quarter. Despite better than expected corporate earnings results, signs of economic stabilization and some modest projections for return to growth, concerns in our sector persist with regard to environmental and tax legislation, regulatory climate, long-term commodity pricing and utility sector performance lagging other growth industries coming out of a recession. Year-to-date in 2010, our industry stock price performance has fallen 8.2% (UTY) compared to a 2.3% loss in the broader market (SPX).

Table 2. Price Performance

Company	Ticker	Price 12/31/09	Price 3/31/10	Price 5/28/10	1Q10 Change	5/28/10 YTD Change
Ameren Corp.	AEE	27.95	26.08	24.66	(6.7)%	(11.8)%
American Electric Power, Inc.	AEP	34.79	34.18	31.96	(1.8)%	(8.1)%
Avista Corp.	AVA	21.59	20.71	19.30	(4.1)%	(10.6)%
CMS Energy, Inc.	CMS	15.66	15.46	14.68	(1.3)%	(6.3)%
Central Vermont Public Service Corp.	CV	20.80	20.17	20.08	(3.0)%	(3.5)%
Cleco Corp.	CNL	27.33	26.55	26.47	(2.9)%	(3.1)%
Consolidated Edison, Inc	ED	45.43	44.54	42.59	(2.0)%	(6.3)%
DPL Inc.	DPL	27.60	27.19	25.04	(1.5)%	(9.3)%
DTE Energy Co.	DTE	43.59	44.60	45.51	2.3%	4.4%
Dominion Resources, Inc.	D	38.92	41.11	38.96	5.6%	0.1%
Duke Energy Corp.	DUK	17.21	16.32	15.96	(5.2)%	(7.3)%
Entergy Corp.	ETR	81.84	81.35	75.07	(0.6)%	(8.3)%
Exelon Corp	EXC	48.87	43.81	38.60	(10.4)%	(21.0)%
FPL Group, Inc.	FPL	52.82	48.33	49.93	(8.5)%	(5.5)%
FirstEnergy Corp	FE	46.45	39.09	35.21	(15.8)%	(24.2)%
Great Plains Energy, Inc.	GXP	19.39	18.57	17.55	(4.2)%	(9.5)%
IDACORP, Inc.	IDA	31.95	34.62	33.05	8.4%	3.4%
MDU Resources Group, Inc.	MDU	23.60	21.58	18.70	(8.6)%	(20.8)%
NiSource, Inc.	NI	15.38	15.80	14.96	2.7%	(2.7)%
Northwestern Corp.	NWE	26.02	26.81	26.34	3.0%	1.2%
PPL Corp.	PPL	32.31	27.71	25.81	(14.2)%	(20.1)%
Pepco Holdings, Inc.	POM	16.85	17.15	16.13	1.8%	(4.3)%
Pinnacle West Capital Corp	PNW	36.58	37.73	35.11	3.1%	(4.0)%
Progress Energy, Inc.	PGN	41.01	39.36	38.59	(4.0)%	(5.9)%
Southern Company	SO	33.32	33.16	32.70	(0.5)%	(1.9)%
TECO Energy, Inc.	TE	16.22	15.89	15.55	(2.0)%	(4.1)%
Wisconsin Energy Corp.	WEC	49.83	49.41	49.00	(0.8)%	(1.7)%
Xcel Energy Inc.	XEL	21.22	21.20	20.49	(0.1)%	(3.4)%
KBCM Electric Utility Index Average					**(2.8)%**	**(7.3)%**
Benchmarks:						
Philadelphia Utility Index	UTY	418.00	399.35	383.72	**(4.5)%**	**(8.2)%**
S&P 500 Index	SPX	1115.10	1169.43	1,089.41	**4.9%**	**(2.3)%**

Note: Results presented cannot and should not be viewed as indicators of future performance.
Source: Thomson Financial

WEATHER

By our weather-tracking estimates, 1Q10 saw mixed temperatures at the extremes compared to the same quarter a year ago. Below-normal temperatures (more heating degree days) from extreme winter storms along the Atlantic Coast brought some of the coolest temperatures recorded to the Southern and Gulf Coast regions. In contrast, the Pacific Northwest and Northeast (Maine) regions saw some of the warmest temperatures (fewer heating degree days) recorded in the 1Q.

Table 3 shows the impact of the weather temperatures (primarily on retail delivery) in the quarter compared to our predictions.

Table 3. 1Q10 Weather Impact — Heating Degree Days

Company	Ticker	1Q10 vs. Normal	1Q10 vs. 1Q09	Estimated Same Qtr YOY EPS Impact	Actual Same Qtr YOY EPS Impact
American Electric Power, Inc.	AEP	12.8%	33.2%	$0.05	$0.06
Avista Corp.	AVA	(16.8)%	(20.4)%	($0.04)	N/A
CMS Energy Corp.	CMS	(8.0)%	(6.9)%	($0.03)	($0.06)
Central Vermont Public Svc. Corp.	CV	(14.2)%	(12.6)%	($0.04)	N/A
Cleco Corp.	CNL	43.9%	110.8%	$0.03	$0.16
DPL Inc.	DPL	5.0%	5.3%	$0.02	N/A
DTE Energy [a]	DTE	(8.1)%	(9.5)%	($0.04)	($0.07)
Dominion Resources, Inc.	D	(4.1)%	(5.4)%	($0.04)	$0.02
Exelon Corp.	EXC	(5.2)%	(5.2)%	($0.01)	($0.015)
FPL Group, Inc. [b]	FPL	130.2% *(58.2)%	122.4% *(52.7)%	$0.04	$0.08
First Energy	FE	(4.8)%	(6.4)%	($0.02)	N/A
Great Plains Energy	GXP	6.8%	16.4%	$0.05	$0.06
Idacorp	IDA	(16.4)%	(15.7)%	($0.05)	N/A
NiSource, Inc.	NI	(1.4)%	(2.0)%	$0.00	($0.015)
Northwestern Corp.	NWE	(0.2)%	2.1%	$0.00	($0.03)
Pinnacle West Capital Corp.	PNW	(24.0)% *(48.8)%	34.6% *(71.5)%	$0.03	$0.02
Progress Energy, Inc.	PGN	52.7% *(81.9)%	48.6% *(80.1)%	$0.07	$0.14
TECO Energy, Inc.	TE	133.4% *(79.2)%	123.1% *(80.5)%	$0.04	$0.05
Southern Company	SO	25.6% *(97.4)%	35.7% *(97.2)%	$0.03	$0.10
Wisconsin Energy Corp.	WEC	(9.1)%	(8.5)%	($0.05)	($0.13)
Xcel Energy, Inc.	XEL	(1.9)%	7.5%	$0.01	$0.00

N/A – not readily available from Company data
** Data is Cooling Degree Days*

a) DTE gas utility only, electric utility has decoupling mechanism
b) FPL utility only; net 4Q weather impact including wind/hydro generation resources was $(0.02) per share

Sources: National Oceanic and Atmospheric Administration (NOAA), KeyBanc Capital Markets Inc. estimates, and Company reports

1Q10 RATINGS AND PRICE TARGET CHANGES

RATING CHANGES

During the quarter, we upgraded shares of IDACORP on February 8, 2010 (see previously published upgrade report titled *"IDA: Idaho Settlement Underappreciated, Upgrade to BUY"*) and then subsequently downgraded back to **HOLD** on February 25, 2010 after shares achieved our price target (see previously published downgrade report titled *"IDA: Price Target Surpassed: HOLD Rating Appropriate"*).

Since the quarter-end, we downgraded shares of Great Plains Energy Incorporated (GXP-NYSE) to **HOLD** on May 4, 2010 (see page 37 for downgrade report titled *"GXP: Price Target Achieved, Reducing Rating to HOLD"*). On May 24, 2010, we downgraded shares of DPL Inc. to **HOLD** and upgraded shares of Cleco to **BUY** (see page 24 for industry report titled *"Utilities Industry: Downgrading DPL, Upgrading CNL for Long-Term Value")*.

Our current research for companies under coverage published since our last Electric Utilities Quarterly through the date of this publication is provided on pages 24-53.

PRICE TARGET CHANGES

We regularly revisit and adjust our price targets on BUY-rated stocks given changes in peer group average P/E multiples and our current economic outlook. Our current price targets on all of our BUY-rated stocks under coverage are outlined in Table 4.

Table 4. Price Target Changes

Symbol	Current Rating	Current Target	Previous Rating	Previous Target	Date Changed
AEP	**BUY**	**$36.00**	BUY	$38.00	02/09/2010
CMS	**BUY**	**$18.00**	BUY	$16.50	04/26/2010
CNL	**BUY**	**$30.00**	HOLD	N/A	05/24/2010
MDU	**BUY**	**$26.50**	BUY	$24.00	01/04/2010

Source: KeyBanc Capital Markets Inc. estimates (as of May 28, 2010)

SECTOR OUTLOOK

In the near to intermediate term, we expect investors will be cautious of the group, as several factors are likely to present valuation overhangs until investors get clarity on the potential length and depth of the economic downturn, timing of any eventual economic recovery, and more direction on national comprehensive energy policies. A slow economy in 2009 impacted electricity sales and pricing, as industrial customers saw reduced demand for their products and residential/commercial customer classes adjusted their spending accordingly. 1Q10 results showed modest signs of the economy stabilizing with generally improving sales comparables from 1Q09, particularly for the industrial customer classes. We remain guarded in our near-term outlook, however, as the sector grapples for fundamentally sound economic footing against a hangover from federal stimulus project funds, homebuyer tax credits and possible expiration of lower dividend taxes at the end of 2010.

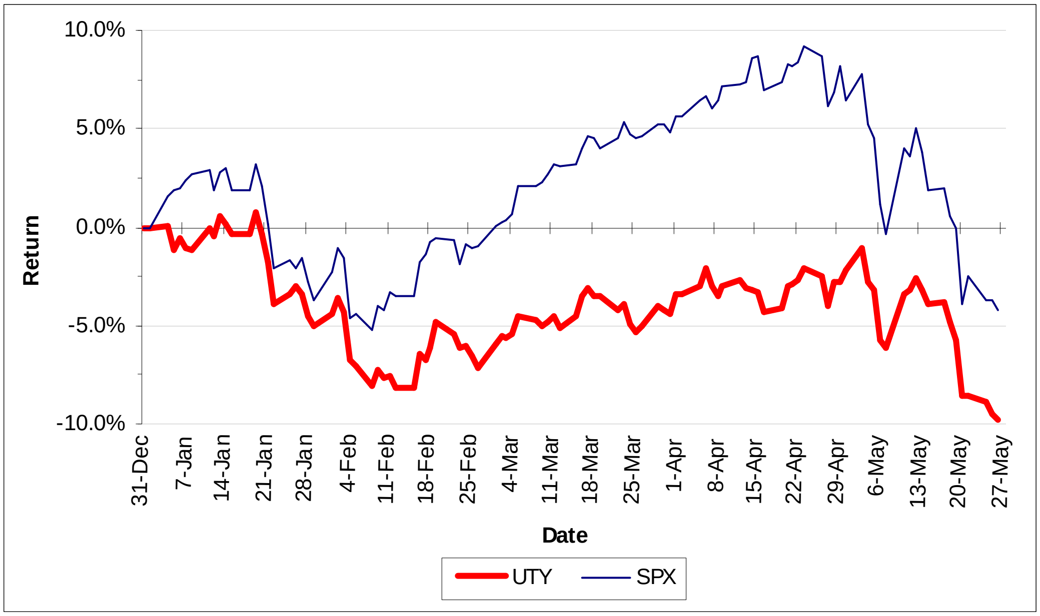
Much of the intermediate to long-term growth in the sector is tied to large capital growth programs earning regulated returns. During a period of lofty valuations and easy credit, investors viewed these programs positively. Recent market performance has made the equity and debt financing of these large projects less attractive. Names within our group that have focused strategies on rate base growth (not including current projects) include: American Electric Power, CMS Energy Corporation (CMS-NYSE), Dominion Resources, Inc. (D-NYSE), DTE Energy, Duke Energy Corporation (DUK-NYSE), NorthWestern Corporation (NWE-NYSE), Pepco Holdings, Inc., Progress Energy, Inc. (PGN-NYSE) and Xcel Energy Inc. (XEL-NYSE).

Although capital markets have improved since early 2009, liquidity and capital costs remain a concern, as costs for credit have generally become more expensive and available durations have shrunk. Higher interest costs will likely continue to pressure earnings until regulatory lag is better addressed. The compression of stock price valuation multiples in the sector has also negatively impacted the equity financing of capital expenditures, as many names are trading below book value. Credit and liquidity concerns have driven many companies to revisit capital spending plans and reassess operational efficiencies. The primary response has generally been to delay projects, as opposed to outright cancellation. Initially, reductions in capital programs were a function of lower growth, which eliminated the need for growth-related capital spending on items such as line extensions and new substations. However, as difficult economic conditions persist, the cuts have grown more extensive, with deferrals in non-core maintenance spending, reevaluating the cost-effectiveness of running older inefficient power plants, and pursuing company restructurings or mergers.

After outperforming the S&P 500 in the preceding five years, the electric utility sector underperformed the market in 2009. We believe the underperformance started with the 4Q08 earnings reporting season, as dividend cuts and disappointing earnings guidance highlighted greater risk than was previously factored into the sector. Consumer electric conservation efforts and economic pressures affecting customer volumes and margins, low commodity pricing, increasingly populist regulatory sentiment, and political uncertainty around carbon and taxes continue to weigh on our sector. As illustrated in Chart 1, 2010 year-to-date industry stock price performance has fallen 8.2% (UTY) compared to a smaller 2.3% loss in the broader market (SPX), some of which may also be attributable to sector rotation as utility sector performance tends to lag other growth industries coming out of a recession.

Chart 1. 2010 YTD Performance of UTY vs. SPX

(December 31, 2009 – May 28, 2010)



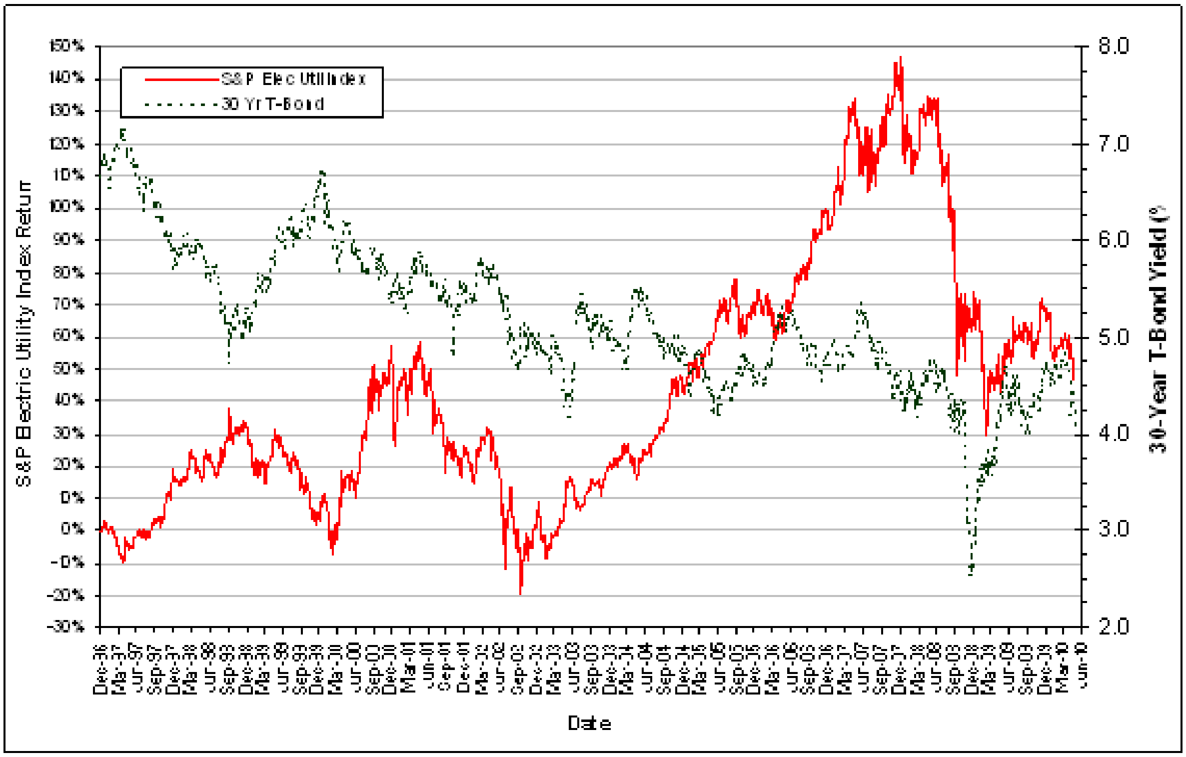
Source: Thomson Financial

We expect the group's stock performance in 2010 will be a function of two primary drivers: commodity pricing and the economy. Retreating high commodity prices have weighed most heavily on unregulated generators with nuclear assets and coal-fired plants (with firm intermediate- to long-term coal contracts). In our view, the companies with the most leverage to unregulated commodity pricing are American Electric Power, Dominion Resources, Entergy Corporation (ETR-NYSE), Exelon Corporation (EXC-NYSE), FirstEnergy Corp. (FE-NYSE), FPL Group, Inc. (FPL-NYSE) and PPL Corporation (PPL-NYSE). Low natural gas prices driven by low electric power demand and increasing shale gas supplies should continue to keep wholesale electricity prices at a depressed level, further exacerbating the margin woes for unregulated generators. Signs of fundamental economic recovery in 2H10 or 2011, however, could lift earnings prospects and price multiples for our entire sector.

From a 2011 P/E perspective, the group now trades at an 11.3x P/E multiple, compared to an 11.6x P/E multiple on the S&P 500 index. On a relative basis, the group is at roughly a 3% discount to the S&P 500, compared to a more historical discount of 25-30%. We believe underperformance is driven by many of the concerns mentioned above and partly due to sector rotation, as many commentators have indicated the U.S. economy may be nearing a bottom, driving investors to sectors with greater potential upside to a more normal economy. Although recent volatility in the broader markets has brought the S&P 500 index P/E multiple closer in line with our sector group P/E multiple, we believe this convergence could rapidly diverge in the other direction once confidence in broader market growth returns. For comparison, Chart 2 shows historical price performance of S&P electric companies compared to the 30-year Treasury bond yield.

Chart 2. Price Performance of S&P Electric Companies and 30-Year Treasury Bond Yield

(December 31, 1996 – May 28, 2010)



Source: Thomson Financial

GROUP INVESTMENT THESIS

Broadly speaking, we believe the long-term fundamentals in the electric utility sector remain essentially intact, as opportunities exist in tight power markets (with scarcity pricing and the potential to rate base needed capacity) needing to modernize aging transmission and distribution infrastructure, meet more environmentally friendly portfolio standards, and serve growing demographics. We are generally more conservative in our long-term growth projections, as the sector historically lags and experiences lower demand growth compared to the broader market.

In an industry that must continue to spend money to make money, regulatory risk is ever present as recovery of capital investment is never 100% assured and companies must seek advanced or later regulatory blessing on large capital expenses to ultimately recover their costs and earn a return on investment once the asset is placed into service. Our concern is that, at some point, rising electricity prices will draw enough political attention that regulators will be pressured to ease the sting on ratepayers, putting the shareholder at risk. We believe the levers in the regulatory toolbox that may be pulled to lower rates include reassessing allowable returns on equity, extending depreciation rates, reviewing costs of debt and reassessing appropriate capital structure. These negative regulatory outcomes had precedence in the 1970s, as high oil pricing and continued nuclear cost overruns prompted regulators to force shareholders to feel some of the pain.

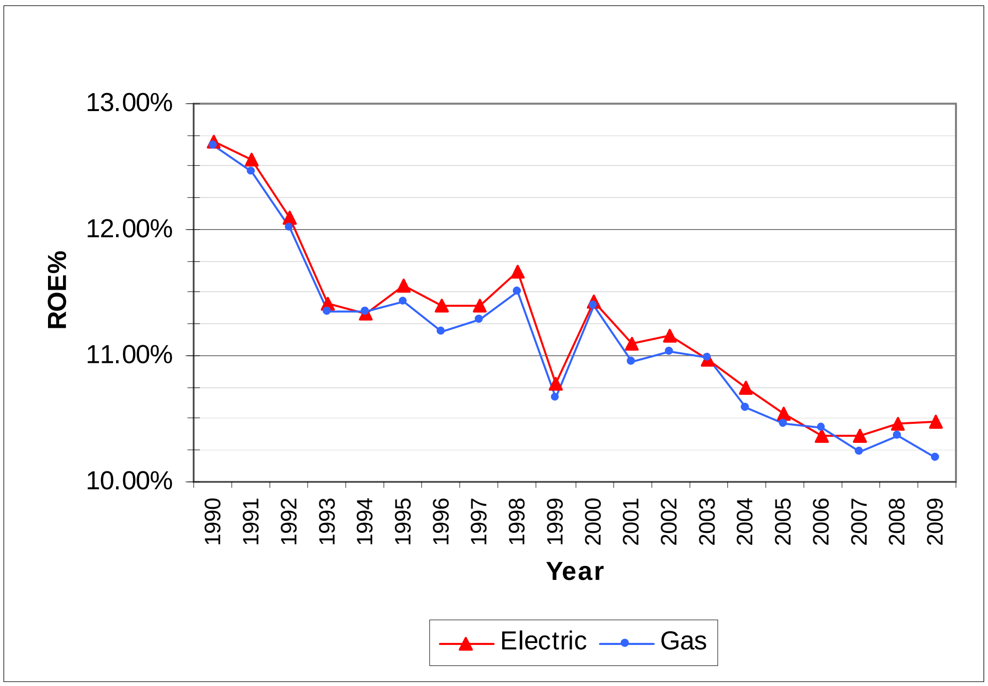
The confluence of several factors highlighted below leaves us concerned about increasing regulatory risk impacting the sector in the coming years. These factors include:

- **Potential for Populist Regulatory Sentiment.** We believe investors must heighten awareness to political and regulatory risk as higher electricity (and overall energy) pricing becomes more scrutinized, especially during periods of a weak economy. We view electricity pricing as being far more exposed to local politics than is the pricing of other energy commodities, and there are always risks to timely and fair recovery of investment dollars, despite prior precedents or assurances.
- **Environmental Capital Expenditures.** On a consolidated basis, the sector must spend tens of billions of dollars to meet more stringent environmental standards that appear to be moving legislative targets subject to changing political winds.
- **Aggressive Rate Base Growth as an Earnings Driver.** Given the low organic growth inherent in the sector, we believe some players may look for a tailwind by growing the rate base as aggressively as possible.

- **Additional Cost Pressure Driven by Inflation.** We believe a weak dollar and long-term global competition for infrastructure materials have increased the rate risk on the proposed capital spend, as projects have an ever-escalating price tag.
- **Potential for Continued Low Interest Rates.** We believe regulatory risk is increased by low treasury yields, as state regulatory commissions often use a spread over treasuries as an indicator of appropriate equity return levels.

To some degree, our concerns are longer-dated as the confluence of regulatory risk factors highlighted above needs time to accumulate. In the short term, we believe that necessary infrastructure investments should and will be encouraged by regulators. More recently, however, the U.S. economic recession has provided support for our more cautious view as evidenced by politicization of rate case proceedings in Florida for FPL Group and Progress Energy. We emphasize that investors should monitor local regulation impacting investments for any move toward restrictive outcomes. Chart 3 illustrates the longer-term trend toward lower regulated utility equity returns authorized by state Commissions.

Chart 3. Average Authorized Equity Returns



Source: Regulatory Research Associates, Major Rate Case Decisions, January 8, 2010

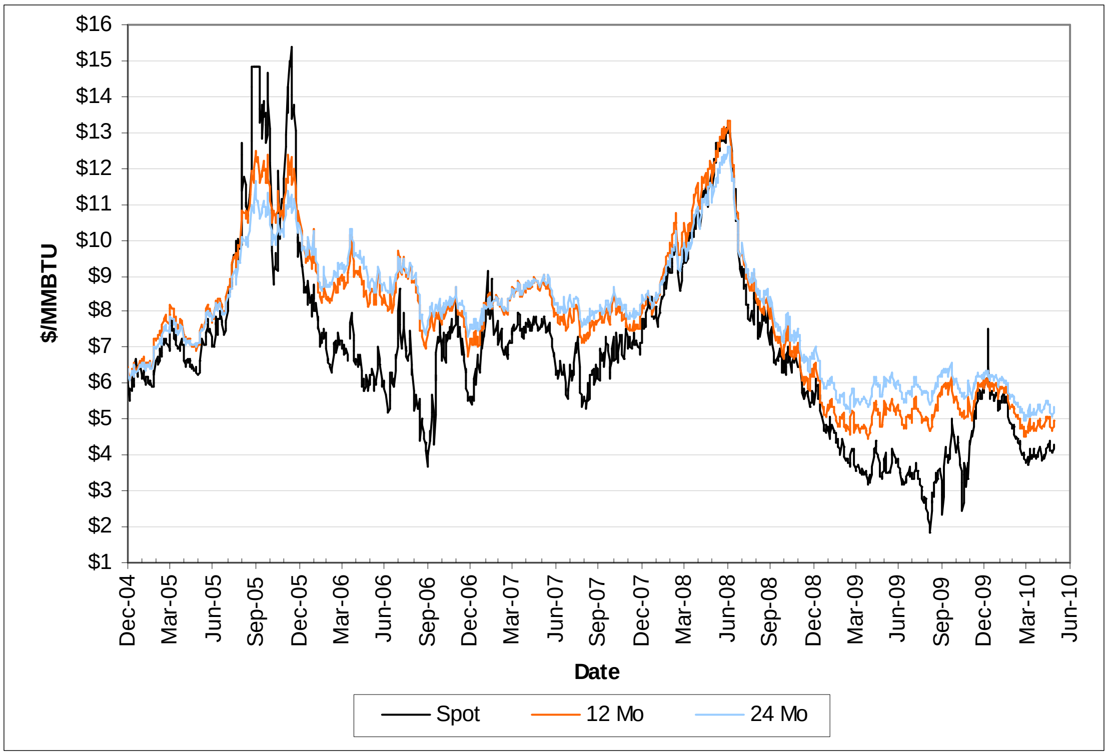
INDUSTRY THEMES

Retreating Commodity Prices and Available Capacity Heat Up Competition

Natural gas pricing, despite having come off of volatile summer 2008 highs, continues to drive the marginal clearing price of power in wholesale markets (see Chart 4). Given the political firestorms that followed rate freeze expirations in Maryland and Illinois, we believe investors should closely monitor the transition to competitive markets in Ohio and Pennsylvania over this year and next. Given the sharp decline in wholesale power pricing throughout 2009 as natural gas prices remain low, we remain concerned over the potential for competitive marketers to undercut pricing, given that supply for the period when these utilities step to market had been partially procured during periods of significantly higher pricing. We believe marketers could lock in supply at current pricing to offer customers a more attractively priced alternative.

Chart 4. Comparison of Spot, 12-Month and 24-Month Natural Gas Prices

(December 31, 2004 – May 28, 2010)



Source: Bloomberg

2010 Mid-Term Elections

We believe utility investors need to monitor the political landscape and mid-term election cycle in 2010 to assess the ongoing implications of who controls Congress, coupled with an Obama Democratic Presidency. In our view, key elements that will drive sector stock movement are: dividend taxation policy, environmental rules, carbon/climate legislation, renewable portfolio mandates and government programs/loans/subsidies for clean energy investment. State elections and ballot initiatives may also have varying impacts for utilities affected by newly elected commissioners or voter-driven ballot initiatives to suspend renewable energy standards (e.g., California A.B. 32) that raise rates while in a weak economy.

Fifteen Percent Dividend Tax Rate Expiration at End of 2010

A reduced 15% tax rate on corporate dividends (same as the long-term capital gains tax rate) provided a positive catalyst for continued investment in higher-yielding stocks when it was introduced in 2003. With a growing federal deficit intensified by war spending in Iraq and Afghanistan, government bailouts of failing industries, stimulus spending bills and the passage of health care reform into law, the issue of extending the dividend tax rate beyond 2010 has become rather uncertain and should garner more headline attention before the end of the year. Counter-intuitively, a weak economy could bolster support for extension, as retirees have already been hit by market declines, and we could see action to protect the value of dividends.

President Obama's budget proposal for 2011, after letting the current income tax rate structure expire in 2010, would increase to 20% from 15% the tax rate on capital gains and dividends for incomes above $200,000 for individuals and above $250,000 for married couples. The lower 15% tax rate on dividends would apply to those below these thresholds. If no accompanying dividend tax legislation is passed and current tax rates expire, the dividend tax would revert back to marginal income tax rates of up to 39.6% for the highest earners in addition to a 3.8% passive income tax that was put in place with the Health Care and Education Affordability Reconciliation Act of 2010 (resulting in a stealth tax increase on dividends totaling up to 43.4% on highest income thresholds).

We believe that the likelihood of allowing the current tax structure to expire is quite high, if only partly mitigated by a drive to protect already suffering retirees. We believe that a lack of long-term dividend tax extension before the end of the year would be a negative catalyst for the utility group as investors start to discount expectations. We believe that 1.0-1.5x P/E multiple points of the group's valuation expansion over the past years were attributable to these lower taxes. While the group generally offers higher yields than the broad market, we expect that, on a relative basis, more highly regulated names with higher payout ratios and yields would underperform, as income-focused investors started to discount expectations, lowering aftertax yields from these companies relative to opportunities in the bond market.

HEIGHTENED IMPORTANCE OF REGULATORY SUCCESS

The major focus of many utilities over the past few years has been the "back-to-basics" approach, through which non-strategic businesses were divested or shuttered, and the business focus returned to the core utility operations. While this scenario has done a great deal to mitigate risk and exposure to volatile market conditions, future growth plans have also come into focus. In the past, companies had pursued diversified opportunities to provide additional growth to offset slower growth in the regulated business. In this new era of focus on the core regulated utility, the importance of regulatory success has come back to the forefront. Companies that are able to craft innovative solutions to issues, such as quick recovery of environmental expenditures, will likely set the stage for future growth of the regulated business. We believe the companies that currently have high levels of exposure to regulatory developments are Ameren Corporation (AEE-NYSE), American Electric Power, CMS Energy, DTE Energy, Exelon, IDACORP, Pepco Holdings and Xcel Energy. We believe a return of high fuel/commodity and construction materials pricing will likely increase regulatory risk, as regulators seek ways to minimize the increases in overall customer electric bills, even at the expense of the shareholder.

FEDERAL ENERGY POLICY ON RENEWABLE STANDARDS, TAX CREDITS AND CLIMATE CHANGE

On December 19, 2007, former President Bush signed into law The Energy Independence and Security Act of 2007. The legislation increased average vehicle fuel efficiency (CAFÉ) standards to 35 miles per gallon by 2020, and contained provisions to promote biofuel production, energy efficiency standards for light bulbs, geothermal energy, and the development of carbon capture and sequestration technologies. The 2007 law did not include a federal renewable portfolio standard (RPS) or an extension of renewable energy production tax credits (PTC) for wind and solar energy that were set to expire at the end of 2008.

In late September 2008, as the U.S. economy and credit market crisis worsened and the renewable energy tax credits expiration deadline loomed, the Senate and House passed a $700 billion economic bailout package (Emergency Economic Stabilization Act of 2008) loaded with $17 billion of renewable energy tax extender provisions, including extending the production tax credit by one year for wind and by two years for geothermal, biomass and marine renewable sources. A 30% solar investment tax credit was extended for eight years.

On February 17, 2009, President Obama signed into law a $787 billion federal economic stimulus package known as the American Recovery and Reinvestment Act of 2009. Related to the sector, the stimulus package included funding for renewable energy production, research and development, loan guarantees for renewable energy and electric transmission technologies, and extended the production tax credit for wind through 2012 and for geothermal, biomass, municipal solid waste, qualified hydropower and marine and hydrokinetic systems through 2013. The stimulus act also allowed qualified PTC-eligible projects to opt for an investment tax credit (ITC) of 30% of a small wind project's installation costs and extended 50% bonus depreciation to projects finished in 2009 and 2010 to allow a long-lived asset to depreciate in five years instead of over its 20- to 30-year lifetime, thereby accelerating expenses for tax purposes and improving cash flow returns. The ITC also extends to building alternative energy component factories and transmission infrastructure.

On June 26, 2009, the U.S. House of Representatives passed H.R. 2454 American Clean Energy and Security Act (Waxman-Markey climate change bill), a bill that includes a federal renewable electricity standard requiring U.S. electric utilities to obtain 15% of their electricity from renewable energy sources and 5% from energy efficiency programs by 2020. A state governor can reduce the renewable requirement to 12% and increase the efficiency requirement to 8% if the state's utilities cannot meet the 15% requirement in time. The bill also places a carbon dioxide emissions cap on U.S. power plants to reduce CO_2 and greenhouse gases by 17% in 2020 compared to 2005 levels, 42% in 2030 and 83% in 2050. In dealing with the allocation of carbon emissions allowances, the final bill allocates 35% of total annual allowances to the electric power sector, of which 30% are given for free to local electric distribution companies to the benefit of all retail ratepayers, 3.5% to merchant coal generators in deregulated power markets and about 1.5% to other generators with long-term purchase power agreements.

The Senate Environment and Public Works Committee pushed through a Kerry-Boxer climate change bill on November 5, 2009 with no changes, as Republicans boycotted the committee markup. The bill calls for 20% CO_2 emissions reduction compared to 2005 levels by 2020 and 83% by 2050. Other substantive amendments may be introduced if a final bill is considered by the full Senate. Passage of a cap-and-trade bill in the Senate may be more difficult, as 25% of the votes that helped pass the bill in the House came from two states (California and New York), representing just 4% of the Senate. There are 25 states where over 50% of their electricity comes from coal. The emissions allowance formula has already begun to set the stage for a contentious debate in the Senate version of the climate change legislation, with some consumer and industry groups calling for improvements. Senators have also discussed adding price collars to limit the costs and volatility in the cap-and-trade program. To date, both Waxman-Markey and Kerry-Boxer bills appear to be going nowhere.

A much awaited Kerry-Lieberman comprehensive energy and climate change bill called the American Power Act was released May 12, 2010. According to an economic assessment study's findings, fossil fuel-based total energy demand would fall from 84% today to 70% in 2030, while renewable and nuclear energy would grow to 16% and 14%, respectively, in 2030 from 8% each of U.S. energy supply today. U.S. oil imports would be reduced by 33-40% below current levels and 9-19% below business-as-usual by 2030, cutting U.S. spending on imported oil by $51 billion to $93 billion per year. The Act would establish an economy-wide carbon price starting at $16.47 per ton in 2013 and growing to $55.44 per ton in 2030, reducing greenhouse gas emissions from covered sources 22% below 2005 levels by 2020 and 42% by 2030. The legislation prompts $41.1 billion in annual electricity sector investment between 2011 and 2030 ($22.5 billion more than business-as-usual) and increases average annual employment by about 200,000 jobs. Households would see an average 3% increase in electricity rates and a 5% increase in gasoline prices between 2011 and 2030, offset largely by energy efficiency improvements.

Future Congressional developments (or delays) on a comprehensive energy bill bear watching. We believe that comprehensive energy reform (carbon cap-and-trade, federal RPS, renewable energy sources, climate change and less reliance on foreign oil), while still important, is likely to get drawn out beyond 2010, as mid-term elections and continued economic weakness may derail or delay any movement on cap-and-trade legislation or a carbon-related tax. Against a backdrop of pressures on the American consumer, job losses and other challenges to American business, our view is that Congress may face tough economic headwinds and lose its political will to add a public "tax" on energy that could cause significant backlash among voters as mid-term elections draw near. Voter resentment could set in if the U.S. economy remains weak, as stimulus programs, government bailouts and the contentious healthcare reform law add to deficit spending, while taxpayers foot the bill and feel left behind in the process. We feel that any volatility in the markets arising from fears about the U.S. economy would also support the view that legislators may not want to raise taxes in this environment, as evidenced by some of the populist backlash fueled by high energy prices in the summer of 2008.

We feel it is important for electric utility investors to become aware of the renewable energy resources available to each utility in each state, consider the business impact as to how an investor-owned utility would address potential federal and state renewable standards and understand the possible implications (favorable and unfavorable) that a potential federal RPS or other energy/climate-related (carbon) legislation may have on their utility investments.

Flawed Clean Air Interstate Rule (CAIR) on Particulate Emissions Is Reinstated by U.S. Appeals Court

On December 23, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) reinstated CAIR by remanding its original July decision without vacatur, essentially stating that leaving the original flawed rule in place until a corrected rule is drafted by the U.S. Environmental Protection Agency (EPA) is better than having no rule at all. The decision means that the emissions allowance cap-and-trade market is functioning again and utilities that had invested in expensive emissions controls equipment are once again able to sell their NOx and SO_2 credits generated from those investments, while others will have to pay more for their non-upgraded, coal-fired plants. Given the state of the capital markets, we had seen many companies scale back or defer future environmental projects in light of the Court's earlier decision to entirely vacate the emissions rules. Currently, the EPA plans to issue a new overhauled CAIR (to comply with the Court's decision) in early 2010, with a final version ready by 2011.

On April 17, 2009, the EPA accepted an endangerment finding stating that greenhouse gases contribute to air pollution that endangers the public health, thus compelling the agency to regulate CO_2 and other greenhouse gases under the Clean Air Act. On November 6, 2009, the EPA sent its endangerment finding to the White House Office of Management and Budget to begin a regulatory review process that would eventually allow the EPA to regulate greenhouse gases on its own. The EPA has not issued any carbon dioxide regulations yet, but is already under a court deadline by November 2011 to issue final rules for new coal plants to implement maximum achievable control technology (MACT) for mercury and other toxic pollutants. Also, EPA Administrator Lisa Jackson has stated that the agency plans to phase-in emissions requirements for permit applications and regulate greenhouse gases for large stationary sources in 2011, although there is growing opposition in the Senate to disapprove the endangerment finding. We ultimately believe that some form of even stricter federal emissions reduction rules (including carbon) will eventually be enacted, although it remains unclear whether the final solution will come administratively through EPA regulations or legislatively through Congress.

By way of background, the CAIR and Clean Air Mercury Rule (CAMR) were issued by the U.S. EPA in 2005. The CAIR program came about after legislation (Clear Skies Act) in 2005 attempting to regulate three (SO_2, or sulfur dioxide, NOx, or nitrogen oxide, and mercury) of four major pollutants from coal-fired power plants failed because the proposal did not also regulate carbon. The Bush Administration then turned to the CAIR and the CAMR as a framework to regulate coal plant emissions, setting up performance standards and cap-and-trade programs.

On February 8, 2008, the D.C. Court of Appeals found that the CAMR and its rules for delisting fossil-based power plants were in violation of the Clean Air Act. On July 11, 2008, the same court threw out the CAIR, concluding the emissions and regional application of its rules were flawed. The electric power industry had been planning for CAIR implementation in 2009 and 2010 by undergoing environmental pollution control projects and the buying and selling of SO_2 and NOx emissions allowances necessary to meet reduction targets. With the CAIR vacated, the industry had been thrown into a state of uncertainty, having to reevaluate environmental capital projects planned or already underway, take write-downs on the value of emission allowances and create a contingency plan for what may come next from federal regulators.

On September 24, 2008, the EPA filed a petition with the D.C. Court of Appeals asking for a rehearing by the full appeals court to revisit its three-judge panel decision in July that vacated the CAIR, citing significant economic impacts, risks to public health and affected state regulations built on the premise of the CAIR's emissions trading program for SO_2 and NOx. On November 5, 2008, Duke Energy, Constellation Energy Group (CEG-NYSE) and AES Corp. (AES-NYSE), the original petitioners that challenged the CAIR's SO_2 trading system and allocation of allowances, responded to the court with briefs supportive of a stay of July's CAIR ruling, recommending that the industry proceed on CAIR Phase I rules through 2014, thereby giving the EPA time until then to rewrite CAIR's Phase II rules to be consistent with the court's original decision.

STATE RENEWABLE PORTFOLIO STANDARDS

Thirty-five states and the District of Columbia have enacted into law RPSs to foster electricity investments in efficiency and renewable resources. The result is a patchwork of different state standards on several factors, including: the ultimate amount or level to be targeted, how to measure the initiative (percent of capacity installed vs. generation output), timeline for implementation, balance between renewables usage vs. gains from efficiency, which renewable resources are to be included in the RPS and even whether the targets being set are voluntary or mandatory.

In Table 5, every state with a date listed has adopted a RPS into law. Five states (North Dakota, South Dakota, Utah, Vermont and Virginia) have set voluntary renewable portfolio goals instead of a mandatory target.

Table 5. State Renewable Portfolio Standards

State law adoption date	Amt	Year	Comments
Arizona 2/26/06	15%	2025	2.5% of total electricity sold from renewable energy sources by 2010 and 15% by 2025. 5% of the renewables to come from solar power in 2007, and will ramp up to a 30% "distributed" energy technology requirement by 2011. Renewable energy from facilities installed before 1/1/1997 are not eligible.
California 9/26/06	20%	2010	Renewable resources include biomass, solar thermal, photovoltaics, wind, geothermal, small hydropower, and ocean-generated power. Targeting a goal of 33% by 2020 for renewable energy used in generation.
Colorado 3/22/10	30%	2020	Requires large investor-owned utilities serving 40,000 or more customers to generate or purchase 12% of their retail electric sales from eligible renewable energy resources (solar, wind, geothermal, biomass, and small hydroelectric) by 2010, increasing to 20% by 2015, and 30% by 2020. 3% of these amounts must come from distributable solar-electric technologies.
Connecticut 6/4/07	27%	2020	20% renewables from "Class I" (solar, wind, sustainable biomass, ocean-generated, landfill gas, 5MW hydro), 3% from "Class I" or "Class II" (trash-to-energy, hydro facilities, and other biomass), and 4% from "Class III" (distributed heat, conservation, waste recovery programs).
District of Columbia 1/19/05	11%	2022	Involves a two-tiered system: "Tier 1" includes solar, wind, biomass, landfill gas, wastewater-treatment gas, geothermal, ocean-generating, and fuel cells from renewable fuels. "Tier 2" includes hydropower and municipal solid waste. Additional 0.386% of the district's renewable energy to come from solar energy by 2022.
Delaware 7/24/07	20%	2019	18% from renewable resources by 2019 (wind, ocean-generated, fuel cells from renewable fuels, 30MW hydroelectric facilities, sustainable biomass, anaerobic digestion, and landfill gas). 2% of state electricity supply from solar PV by 2019.
Florida	20%	2020	An Executive Order from July 13, 2007 requires utilities to produce at least 20% of their electricity from renewable resources. On 1/30/2009, the Florida Public Service Commission proposed a RPS to the state Legislature requiring 20% generation from renewable resources by 2020. Other target dates: 7% by 2013, 12% by 2016 and 18% by 2019. On May 1, 2009, the Florida House left the bill in committee as regular session came to a close, effectively tabling RPS legislation at least until 2010.
Hawaii 6/25/09	25%	2020	10% of net electricity sales to come from renewable sources by 2010, 15% by 2015 (wind, solar, ocean thermal, wave, and biomass). On June 25, 2009, RPS was increased to 25% by 2020 and 40% by 2030. 30% by 2030 to come from energy efficiency savings.
Iowa 10/21/83	105 MW		Not an official RPS, but 1983 Alternative Energy Production state law mandates two investor-owned utilities (Mid-American and Interstate Power/Light) to own or contract for 105 MW of renewable power (photovoltaics, landfill gas, wind, biomass, hydro, municipal solid waste, and anaerobic digestion).
Illinois 8/28/07	25%	2025	10% by 2015 and 25% by 2025. 75% of the electricity used to meet the RPS must come from wind power generation, 6% from new solar photovoltaic by 6/1/2015. Eligible renewables include solar, biomass, and existing hydropower. Utilities to implement energy efficiency standard to reduce electric usage by 2% of demand by 2015.
Kansas 5/22/09	20%	2020	Generate or purchase renewable energy of 10% by 2011, 15% by 2016 and 20% by 2020 and beyond. Eligible sources include wind, solar thermal and photovoltaic, dedicated agricultural or plant waste, untreated wood, fuel cells, existing hydropower and new hydropower of 10 MW or less.
Maine 9/28/99	10% new	2017	Original standard of 30% by the year 2000. RPS was increased in June 2006 an additional 10% by 2017 for new renewable sources (fuel cells, tidal power, solar, wind, geothermal, hydro, biomass, or municipal solid waste recycling) placed into service after 9/1/05.
Maryland 4/24/08	20%	2022	RPS accelerated to 20% of state's electricity supply must come from renewable sources by 2022. At least 2% must come from solar sources and 7.5% from other renewable sources (wind, biomass, anaerobic digestion, landfill gas, geothermal, ocean-generated, fuel cells from renewable fuels, and small hydro) by 2022.
Massachusetts 7/2/08	15%	2020	New law updates previous RPS of 4% in 2009 to 15% new renewable electricity generation by 2020 with 1% increase each subsequent year, up to 25% by 2030. Renewables include solar, wind, ocean, fuel cells from renewable fuels, landfill gas, biomass, marine, and geothermal.
Michigan 10/6/08	10%	2015	Qualifying sources include wind, solar, hydropower, landfill gas, waste combustion and cogeneration. Advanced fossil fuel technologies and efficiency measures may be used to cover some of a utility's obligation.
Minnesota 2/22/07	25%	2025	Xcel Energy (generates about half of the state's electricity) required to produce 30% from renewable sources by 2020. "Eligible Renewable Energy Technologies" include solar, wind, small (<100MW) hydroelectric, hydrogen from renewable resources, and biomass.
Missouri 11/4/08	15%	2021	Voters passed proposition C for state-wide RPS repealing current voluntary standard. Investor-owned utilities qualify with their own generation or renewable energy credits. Commission and Dept. of Natural Resource to write the annual certification rules. 2% by 2011; 5% by 2014; 10% by 2018.
Montana 4/28/05	15%	2015	Utilities can meet the standard by entering into long-term purchase contracts for electricity bundled with renewable energy credits. The law includes cost caps that limit the additional cost utilities must pay for renewable energy. Resources include wind, solar, geothermal, existing hydro, landfill or farm-based methane gas, wastewater-treatment gas, nontoxic biomass, and fuel cells from renewable fuels.
Nevada 6/8/09	25%	2025	20% by 2015, at least 5% must be generated from solar energy. Utilities can also earn credit for up to 25% of the RPS through energy efficiency measures. Resources include biomass, fuel cells, geothermal, solar, hydro, and wind. On June 8, 2009 RPS was updated to 25% by 2025 (6% from solar by 2016).
New Hampshire 5/11/07	25%	2025	25% of state's electricity from renewable resources by 2025 (includes wind, solar, geothermal, hydrogen fuels, methane gas, ocean-generated, biomass, and existing small hydroelectric sources).
New Jersey 4/12/06	22.5%	2021	2% of RPS must come from solar sources. Resources include solar, wind, wave, tidal, geothermal, landfill methane gas, fuel cells from renewable fuels, anaerobic digestion of food waste and sewage sludge at a biomass generating facility, and hydropower.
New Mexico 3/5/07	20%	2020	20% of an electric utility's power must come from renewable sources. Resources include solar, wind, hydropower, geothermal, fuel cells from renewable fuels, and qualifying biomass. Performance-based financial or other incentives are used to encourage utilities to exceed annual standards.
New York 9/22/04	25%	2013	25% from renewable resources by 2013, categorized into two-tiers. "Main Tier" is mandatory 24% of RPS (biogas, biomass, liquid biofuel, fuel cells, hydroelectric, solar, ocean or tidal power, and wind). "Customer-Sited Tier" is remaining 1% of renewable energy sales to come from voluntary programs (fuel cells, solar, and wind resources).
North Carolina 8/20/07	12.5%	2021	By 2021, 12.5% of retail sales must come from renewable energy or energy efficiency for investor-owned utilities. 10% by 2018 for electric cooperatives and municipal utilities.
North Dakota* 3/21/07	10%	2015	Voluntary RPS passed by legislature of 10% retail electricity sold to come from renewables by 2015.
Ohio 5/1/08	25%	2025	12.5% electricity sold in the state to come from renewables (wind, solar, hydropower, geothermal, or biomass), half of which must be generated in Ohio. Other 12.5% may come from alternative energy resources (nuclear power plants, fuel cells, energy-efficiency, and clean carbon capture technology). Utilities may buy, sell, and trade renewable energy credits to comply. 22.5% by 2025 to come from energy efficiency savings. Electric utilities must reduce peak energy demand 1% in 2009, and an additional 0.75% each year through 2018.
Oregon 6/6/07	25%	2025	25% of utility electric load from new renewable sources by 2025. Resources include wind, solar, wave, geothermal, biomass, new hydro or upgrades to existing hydro facilities. 20 MW by 2020 to come from solar photovoltaic.
Pennsylvania 12/16/04	18.5%	2020	Two-tiered resources to meet RPS: 8% from Tier 1 (wind, solar, coalmine methane, small hydropower, geothermal, and biomass), 10% from Tier 2 (waste coal, demand side management, large hydropower, municipal solid waste, and IGCC), and 0.5% must be solar-provided generation by 2020.
Rhode Island 6/29/04	16%	2020	3% of retail electricity sales must come from renewable energy by 2006, increasing 1% a year through 2020. Existing renewables count for only 2% of RPS, the rest must be from new renewable production. Resources include direct solar radiation, wind, ocean-generated, the heat of the earth, small hydroelectric facilities, eligible biomass, and fuel cells using renewable fuels. The PUC will review/revise the schedule after 2013.
South Dakota* 2/21/08	10%	2015	Voluntary RPS of 10% retail electricty sold to come from renewables by 2015.
Texas 8/1/05	5,880 MW	2015	Law targets 5,880 MW of new renewable generation to be built in state (about 5% of the state's electricity demand) by 2015. Goal of 10,000 MW in renewable generation capacity by 2025. 500 MW by 2025 from non-wind resources.
Utah* 3/18/08	20%	2025	Voluntary RPS goal of 20% by 2025. Utilities to pursue cost-effective renewable energy.
Vermont* 6/14/05	10%	2013	Voluntary goal of 10% of 2005 total electric sales to be achieved by 2012, else RPS will become mandatory in 2013. Renewable resources include wind, solar, small hydropower, landfill methane gas, anaerobic digesters, and sewage-treatment facilities excluding municipal solid waste. Vermont utilities can build generation out of state to comply with RPS. On 3/20/08, new renewable goal of 25% by 2025 empahsizing use of Vermont's farms and forests.
Virginia* 4/11/07	12%	2022	Voluntary RPS goal of 12% of 2007 base year utility electricity sales (excluding average nuclear power supply) by 2022. Resources include solar, wind, geothermal, hydropower, wave, tidal, and biomass energy. Wind and solar receive a double credit toward RPS goals. Investor-owned utilities are incentivized with increased rate of return to procure a percentage of the power sold in VA from eligible renewable energy sources.
Washington 11/7/06	15%	2020	All utilities in WA serving more than 25,000 people must produce 15% of their energy using renewable sources by 2020. Resources include water, wind, solar, geothermal, landfill gas, wave, ocean, tidal power, gas from sewage treatment facilities, biodiesel fuel not from deforested land and biomass.
West Virginia 6/17/09	25%	2025	10% by 2015 and 15% by 2020 from alternative or renewable energy sources. Eligible alternatives include advanced coal technology (e.g., carbon capture and storage, ultra/supercritical and pressurized fluidized bed technologies), coal bed methane, natural gas, coal gasification or liquefaction facility-produced fuel, synthetic gas, IGCC, waste coal, tire-derived fuel, pumped storage hydroelectric, and recycled energy. Eligible renewables are solar, wind, hydropower, geothermal, biomass, biofuels, and fuel cells.
Wisconsin 3/17/06	10%	2015	Qualifying renewables include tidal and wave action, fuel cells using renewable fuels, solar, wind, biomass, geothermal technology, and hydropower less than 60 MW. Renewable energy generated outside of Wisconsin is eligible.

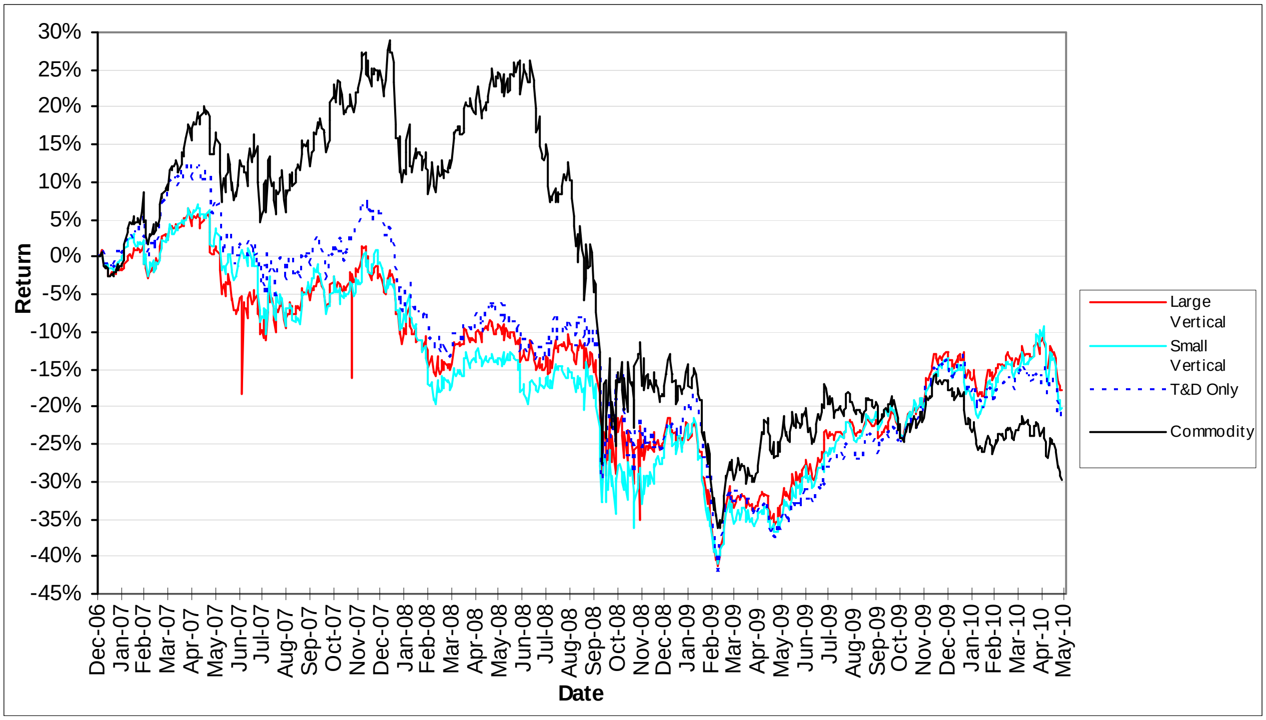
* Denotes states that have set voluntary goals for adopting renewable energy standards instead of mandatory targets.
Sources: http://www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm
http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm
Company data, KeyBanc Capital Markets Inc.

Stock Performance Divergence Based on Commodity Exposure

The strong (if not volatile) commodity cycle had for years been favorable for companies that have exposure to natural gas and/or coal, as they have typically outperformed the rest of the group, as depicted in Chart 5. In 2009, the commodity subgroup fared the worst in the economic downturn, as natural gas, coal and power prices have fallen with a weaker economic outlook. Despite a brief period of outperformance in spring 2009, any investor enthusiasm in the commodity subgroup dampened over the summer. We believe that the rapid and pronounced price declines are driven by several factors: the collapse of major banks likely drove forced liquidation of long commodity positions; reduced demand in light of a slowing global economy (especially China, which had been a major importer); volatility arising from marketplace assumptions on the effects of various government stimulus programs around the world; opening of new unconventional natural gas plays (with improving production technology); and conservation efforts at the residential level.

Chart 5. Price Performance of Different Utility Subgroups

(December 31, 2006 – May 28, 2010)

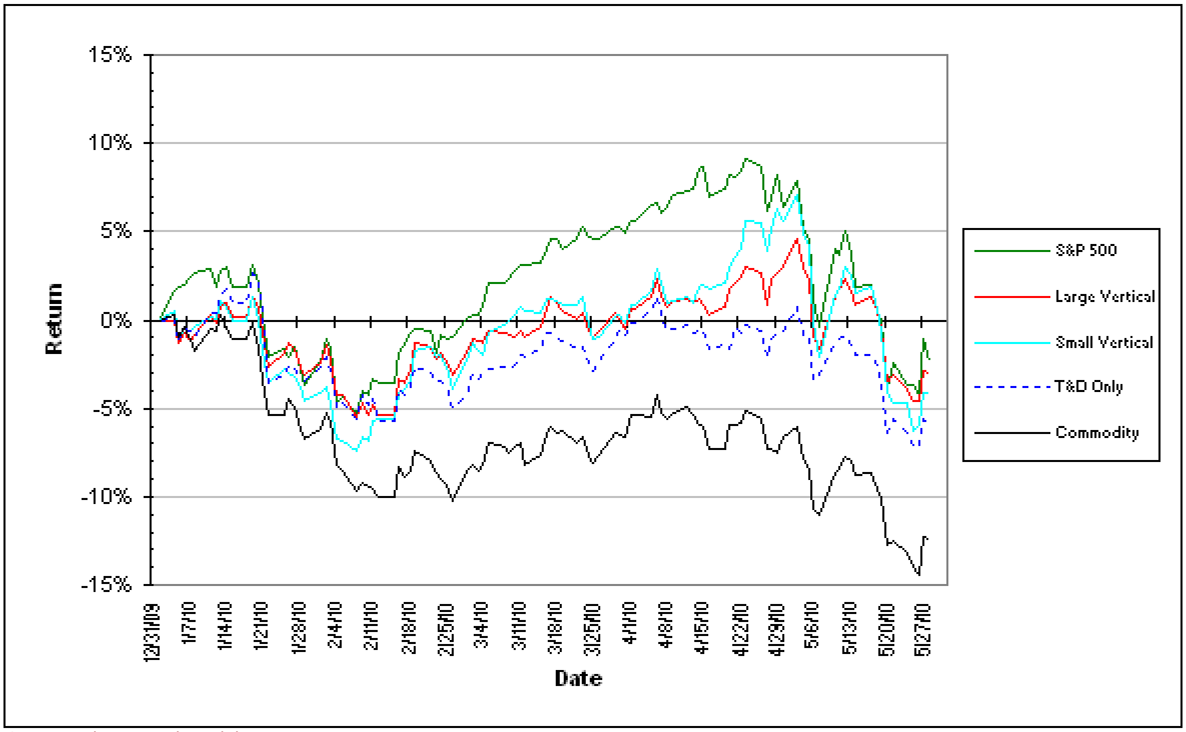


Source: Thomson Financial

As shown in Chart 6, the recent run-down for commodity-focused names at the end of last year continues into 2010 and may be due to investors realizing that the economic recovery may be slower and longer-dated and that demand is down due, in part, to a shift in changing consumer behaviors. Transmission and distribution names had been stronger performers in our sector earlier this year as investors sought to benefit from potential U.S. infrastructure spending on transmission grid stability and the incentive returns granted for these projects, but sentiment may have turned somewhat negative as project timelines were being delayed and purposefully reassessed to adjust to current economic reality. Small and large vertically integrated utilities had recovered to above breakeven for the year, but fell in May along with the rest of the broader market (see Chart 5).

Chart 6. Year-to-Date S&P500 vs. KBCM Electric Utility Segment Performance

(December 31, 2009 – May 28, 2010)



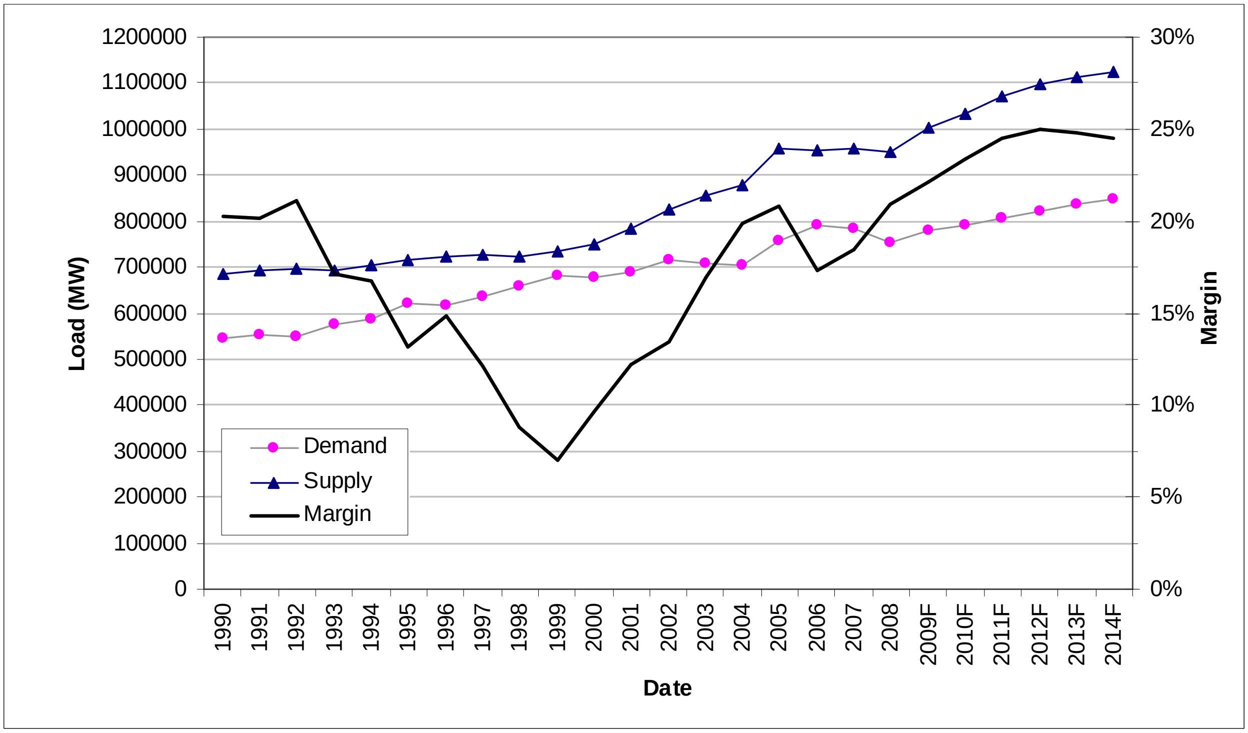
Source: Thomson Financial

NEW GENERATION / TRANSMISSION BUILD TO MEET LOAD GROWTH

On the supply side, the industry has worked off much of the capacity glut that resulted from a late 1990s building frenzy, which was fueled by cheap natural gas, robust economic growth and optimistic investors. Regionally, several parts of the country have recognized the fact that long construction lead times (particularly for baseload generation) suggest a sense of urgency around planning for new capacity. The recent economic slowdown, however, has temporarily slowed demand growth while new capacity projects were already underway, thus improving load margins in the intermediate forecast term (see Chart 7).

Chart 7. Historical and Forecasted U.S. Electric Supply and Demand

(Summer)

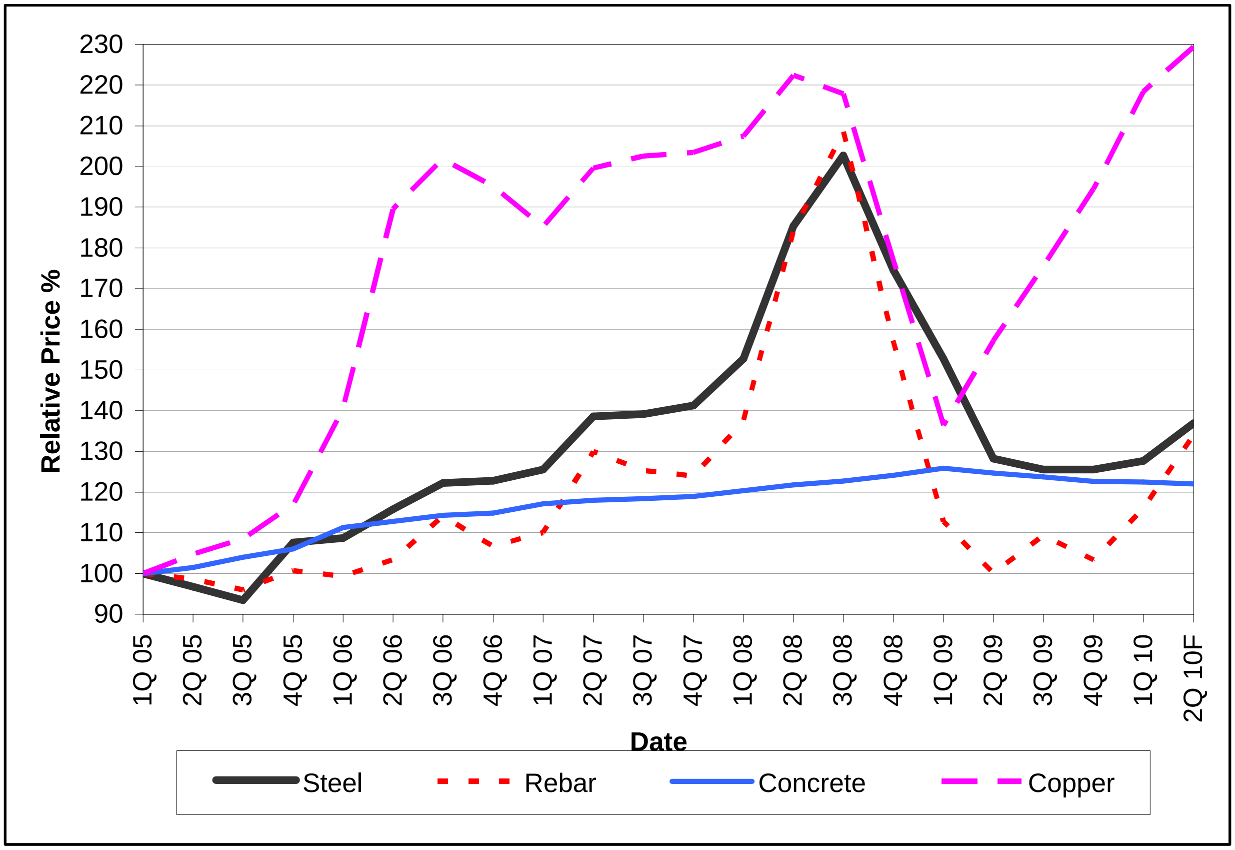


Source: North American Electric Reliability Corp, 2009 Historic Capacity and Demand Report

COST ESCALATION IN NEW GENERATION BUILD

While recent prices may have come off of their earlier highs due to the global economic crisis slowing construction demand, we believe the long-term trend of rising construction materials costs could resume once the global economy rebounds. The cost of building new generation remains a moving target, as worldwide demand for construction materials commodities (steel, concrete and copper), labor and components (turbines and boilers) would remain fundamentally strong, driven by a rebound in the U.S. and Chinese economies. We believe this presents challenges to both unregulated and regulated investment in new generation plants. In particular, on the regulated side, there exists a chicken-and-egg problem in that securing pricing without a regulatory buy-in is as difficult as receiving regulatory pre-approval without firm pricing. For example, in order to secure the project's expected final approval, Southern Company subsidiary Mississippi Power agreed to a cost cap on its 582MW Kemper County IGCC plant at $2.88 billion to allow the Commission to protect and assure customers against uncontrolled cost increases from its original $2.7 billion estimate. In addition to this regulatory quagmire is uncertainty around the cost to achieve yet unknown environmental controls to mitigate carbon output. Chart 6 illustrates the upward pressure on construction commodities, with the global economic slowdown affecting prices in the near term and some recent indications and forecasts of price stabilization. As an example of longer-dated cost escalation on new generation build, Progress Energy recently estimated the cost of building two new nuclear plants, with necessary transmission, at $17 billion, over twice initial estimates.

Chart 8. Construction Materials Indexed Pricing



Source: Bureau of Labor Statistics and Steel Business Briefing (as of May 28, 2010).

The long-term trend of rising costs increasingly necessitates the need for rate-making mechanisms, such as Construction Work In Progress (CWIP), to allow utilities to undertake construction without significantly weakening their balance sheet, cash flow and credit metrics. Additional cost pressures on ratepayers pose the risk of regulators authorizing lower ROEs in future rate proceedings to offer some rate relief.

STRONGER M&A PLAYERS CONSERVATIVE, BUT COULD BE OPPORTUNISTIC

We expect that many utility executives are looking at the potential synergies of a strategic and well-executed merger with great interest. Companies with substantial unregulated operations would most likely be able to realize the greatest amount of synergies, as these savings are generally outside the reach of regulators. With balance sheets generally repaired (and the potential for all-stock deals to offer further improvement), we consider additional consolidation to be likely in the long term. The outlook for an extended period of low power prices may accelerate M&A to achieve cost synergies. In the near term, however, we believe players may be waiting for political and regulatory support in understanding the realities of eventual increases in energy prices and for credit markets to improve enough so that companies with strong balance sheets that are currently preserving capital can become opportunistic in supporting weaker players (see Table 6).

Possible Acquirees

DPL Inc.

The built-in poison pill (the financial portfolio) has been unwound; however, the new management team is hard to read with regard to potential M&A. We believe DPL Inc. (DPL-NYSE) would be a good fit for American Electric Power (AEP-NYSE) or Duke (DUK-NYSE).

NiSource, Inc.

We believe NiSource, Inc. (NI-NYSE) is perceived as an acquisition target. However, we believe a presence in several jurisdictions would present considerable risk of achieving reasonable approvals across the board. Further, we believe a newly implemented five-year plan and the hiring of a new CEO suggests that management will continue down the path of getting back on course alone.

TECO Energy, Inc.

We group TECO Energy, Inc. (TE-NYSE) with DPL Inc. We believe their relatively small sizes in single state utility jurisdictions make them attractive candidates for contiguous mergers. TECO's coal assets make it an intriguing name as well.

Possible Acquirers

Exelon Corporation

Exelon's failed hostile bid attempt for NRG Energy Inc. (NRG-NYSE) has temporarily sidelined the Company in the M&A arena. While Exelon management has stated that it has no near-term acquisition plans, we feel that Exelon will continue to look for additional M&A opportunities in the long term. We believe Exelon is well positioned to enjoy strong cash flows well into the next decade. While the Company has previously signaled that it could pursue share repurchases, it has not ruled out pursuing acquisitions. We believe management would like to increase the scale of its unregulated, low-cost generation fleet, with a bias toward low-carbon assets.

Southern Company

With historically strong currency, we expect Southern is looking at potential acquisitions. Given the relative ease of asset purchases compared to whole companies, we suspect Southern may be interested in tucking in merchant assets at its Southern Power subsidiary. Liquidity pressures at merchant players could be alleviated by divestitures. Unlike the last market downturn, we do not envision private equity putting a floor on generation valuations. Alternatively, if Southern were to pursue a whole company, we believe management may seek to green up the Company's generation portfolio, which is currently heavily coal-burning.

Recent M&A Activity Update

PPL Corp. and E.ON U.S.

On April 28, 2010, PPL announced the purchase of Louisville Gas & Electric and Kentucky Utilities (U.S. assets of German utility E.ON) for $7.625 billion (includes $450 million in acquired tax benefits). PPL acquired 8,077 MW regulated generation capacity, which should diversify and rebalance its business mix from standalone company-projected EBITDA in 2010 from 30% regulated / 70% competitive mix to 55-60% regulated / 40-45% competitive mix in 2011. Financing is to be accomplished with $2.0 billion-$2.6 billion of new common equity, $2.1 billion in first mortgage bonds, $800 million corporate debt (at LG&E and KU) and $750 million-$1.0 billion "high-equity-content securities". Additionally, PPL indicated that it could raise capital through the divestiture of non-core assets and has $250 million-$750 million in cash on hand. The transaction is targeted to close by the end of this year and requires approvals by state regulators in Kentucky, Virginia and Tennessee, as well as by FERC.

Conectiv Energy (Pepco Holdings Inc. subsidiary) and Calpine Corp.

On April 21, 2010, Calpine Corp. (CPN-NYSE) announced it was purchasing the 4,490 MW merchant generation fleet of Pepco Holding Inc's (POM-NYSE) subsidiary Conectiv Energy for $1.65 billion. Conectiv Energy's remaining non-core assets/contractual obligations (load service supply, energy portfolio hedges and certain tolling agreements) are expected to be kept by POM and liquidated through 1Q11, and together with the return of collateral and working capital, should result in about $350 million-$450 million in additional cash funds. After $300 million in estimated taxes, POM expects to use $1.75 billion in net proceeds from the transaction for parent debt reduction. The transaction is targeted to close by June 30, 2010.

POM management estimates the transaction will improve the Company's credit profile to a mid-15% FFO/Debt ratio by 2011 (vs. 13% 2009 actual), lower its Debt/Capitalization ratio to 54% by 2011 (vs. 57% 2009 actual), and be modestly accretive to earnings per share in 2012. The sale also eliminates the need to issue any new equity until at least 2012 (excludes Dividend Reinvestment Plan equity issues of approximately $40 million annually).

FirstEnergy Corporation and Allegheny Energy, Inc.

On February 11, 2010, in a surprise move, FirstEnergy Corporation (FE-NYSE) and Allegheny Energy, Inc. (AYE-NYSE) announced an all-stock merger between the two companies. FirstEnergy would offer 0.667 FE shares for each share of AYE stock, representing a 31.6% premium to the previous day's closing stock prices or a value of $4.7 billion. FE also would assume $3.8 billion of AYE's debt, making the deal's implied combination value around $8.5 billion.

Allegheny Energy is a diversified utility holding company with both regulated and unregulated operations, consisting of 9,730 MW of total generating capacity (2,744 MW regulated; 6,986 MW is unregulated) serving approximately 1.6 million customers in Pennsylvania, West Virginia, Maryland and Virginia. Its fuel mix by generating asset is primarily 79% coal, 12% hydro and 9% natural gas.

In our view, the deal is a natural fit for FirstEnergy with regard to scalability, fleet optimization and geography, but projected earnings accretion and transaction synergies are subject to a high degree of regulatory approval risk of claw-back for ratepayer benefit. Also, the combined generation portfolio still retains a heavy carbon footprint at about 64% coal-fired generating capacity and leaves 19% of the fleet unscrubbed for other environmental emissions regulations. We believe that the state regulatory approval process will likely take longer than the 12-14 months estimated by the companies. Although Maryland allows a six-month timetable for review, Pennsylvania and Maryland are states that both follow a "public benefits" standard for merger approval. West Virginia applies a "no worse off" test and Virginia applies a "no impairment" standard.

Table 6. Recent Utility M&A Activity

Date Announced	Acquirer	Acquiree	Consideration	Offer Price per Share	Implied Value at Announcement	Premium at Announcement
4/28/10	PPL Corporation	E.ON U.S. (Louisville Gas & Electric and Kentucky Utilities)	100% Cash	N/A	$7.625 billion	N/A - Private
4/21/10	Calpine Corporation	Conectiv Energy Holding Co.	100% Cash	N/A	$1.65 billion	N/A - Subsidiary
4/11/10	Mirant Corporation	RRI Energy, Inc.	100% Stock	0.353 shares	$1.63 billion	4.4%
2/11/10	FirstEnergy Corporation	Allegheny Energy, Inc.	100% Stock	0.667 shares	$8.5 billion	31.6%
10/20/08	Exelon Corporation	NRG Energy, Inc.	Failed	0.485 shares	$6.1594 billion	36.7%
10/26/07	Macquarie Consortium	Puget Energy, Inc.	100% Cash	$30.00	$7.4 billion	25.3%
6/25/07	Iberdrola SA	Energy East Corporation	100% Cash	$28.50	$8.5074 billion	24.7%
2/26/07	KKR	TXU Corp.	100% Cash	$69.25	$44.1614 billion	15.4%
2/7/07	Great Plains Energy Inc.	Aquila Inc.	55% Cash and 45% Stock	$1.80 and 0.0856 shares	$2.8736 billion	-2.7%
7/8/06	MDU Resources Group	Cascade Natural Gas Corp.	100% Cash	$26.50	$471.2 million	23.5%
7/5/06	Macquarie Consortium	Duquesne Light Holdings Inc.	100% Cash	$20.00	$2.5918 billion	21.7%
4/25/06	Babcock & Brown	NorthWestern Corporation	Failed	$37.00	$2.0520 billion	15.3%
12/19/05	FPL Group	Constellation Energy Group, Inc.	Failed	$52.02	$14.4208 billion	15.0%

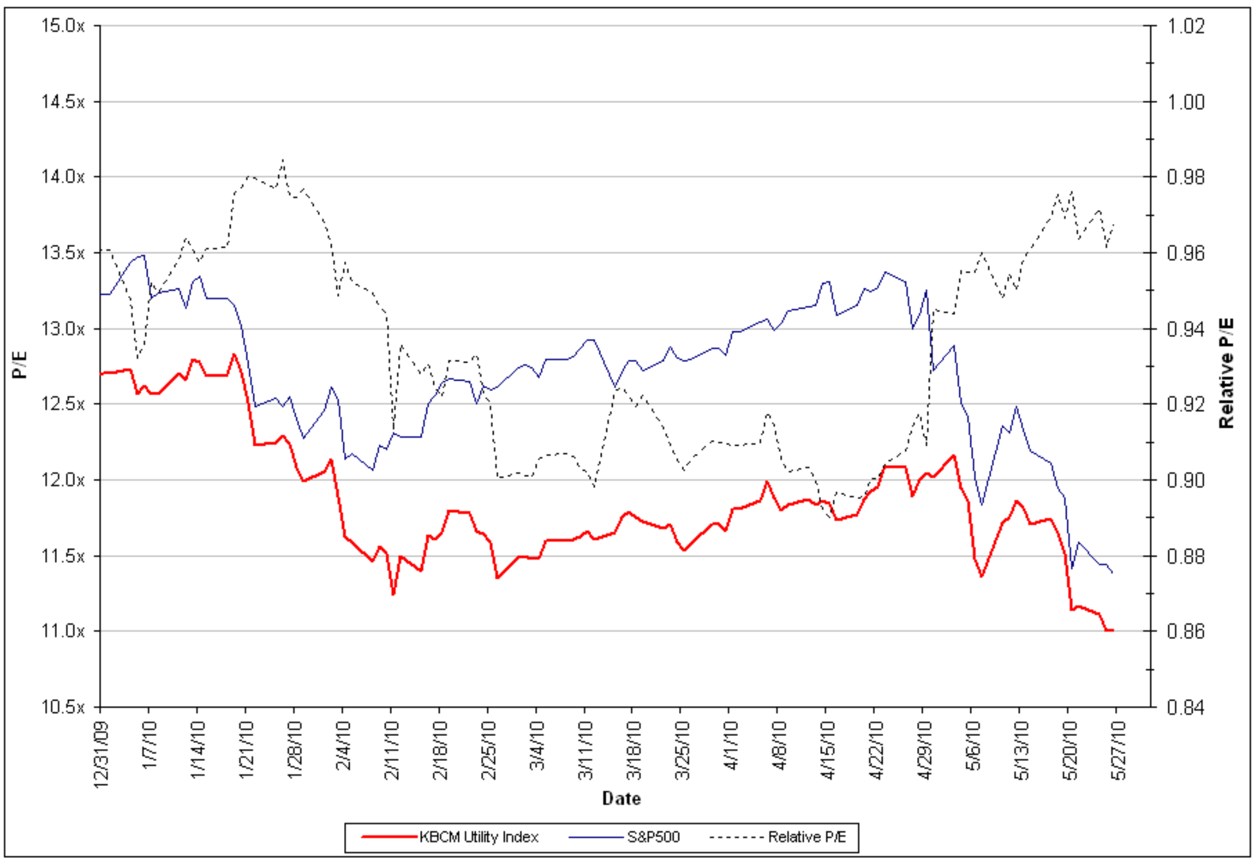
Source: Company data, KeyBanc Capital Markets Inc. estimates

SHORT INTEREST OVERVIEW

Recent volatility and concerns in the broader markets have brought the S&P 500 index's 2011 P/E multiple closer in line with our sector group P/E multiple (see Chart 9). Historically, underperformance in our sector has provided opportunities for investors to cover their short positions, as evidenced in Table 7 by the decline in short interest following the end of 2009. Previously, 2008 ended with a sharp drop-off in short interest positions (most likely attributable to the credit market turmoil forcing investors to short cover in order to close out hedge positions or to meet maintenance calls and redemption requirements). Beginning in 2009, short interest crept back up, with the increase being driven by names with commodity exposure or concerns around liquidity. Short interest steadily decreased over the summer and into the fall, as broader market strength may have led to some closing out of short positions. The 2009 short interest year ended higher primarily due to large-cap names Duke, Dominion and Exelon, as investors may have started realizing that any robust economic recovery for electric utilities may take longer than expected. Modest short interest declines in early 2010 may have been driven by early hopes of economic recovery. Most recently, the month of May saw short interest increase as global economic concerns started to gain momentum.

Chart 9. YTD 2011 P/E Comparison of KBCM Utility Coverage vs. S&P 500

(December 31, 2008 – May 28, 2010)



Source: Thomson Financial

Table 7. Monthly Short Interest

			(days)	(shares in millions)																	
		Shares	Current	2010					2009												2008
Company	Ticker	Out	Short Ratio	May	Apr	Mar	Feb	Jan	Dec	Nov	Oct	Sep	Aug	Jul	Jun	May	Apr	Mar	Feb	Jan	Dec
Ameren Corp.	AEE	238.3	3.09	7.7	6.6	5.7	4.5	3.9	4.5	4.4	4.4	3.7	11.0	8.1	8.8	7.8	5.3	4.9	3.6	3.1	3.3
American Electric Power Co.	AEP	478.9	0.83	4.8	4.6	5.1	4.7	9.0	11.4	9.8	7.0	7.5	6.8	7.1	6.4	4.6	5.4	5.8	4.3	5.1	6.2
Avista Corp.	AVA	54.9	7.10	2.3	2.1	2.0	2.1	2.4	2.5	2.7	3.1	2.8	2.9	2.8	2.4	1.7	1.2	1.3	1.6	1.9	2.5
CMS Energy Corp.	CMS	229.9	7.97	36.3	37.5	33.3	32.9	32.6	31.3	32.1	30.5	28.0	28.1	26.8	27.0	24.9	27.0	27.1	28.7	30.0	21.7
Central Vermont Public Svc. Corp.	CV	12.0	5.22	0.5	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Cleco Corp.	CNL	60.7	3.89	2.4	2.0	2.3	2.8	2.4	2.5	3.4	3.5	3.9	4.4	4.0	3.6	3.7	3.6	3.1	1.9	2.3	2.3
Consolidated Edison, Inc	ED	282.0	3.34	8.0	6.6	6.5	7.4	9.4	9.3	9.6	9.7	10.9	11.7	11.1	12.6	11.6	12.5	7.7	7.7	7.5	9.1
DPL Inc.	DPL	118.9	3.21	3.0	2.6	2.9	2.6	3.6	3.4	3.8	6.1	6.8	5.3	10.8	10.9	10.3	10.9	11.3	11.9	13.3	13.3
DTE Energy Co.	DTE	168.4	4.45	7.1	6.4	5.6	6.5	7.2	7.9	5.6	3.8	4.2	3.2	3.2	3.0	3.1	2.9	2.6	4.2	3.7	2.5
Dominion Resources, Inc.	D	596.1	3.84	12.3	13.9	15.0	12.9	11.3	15.5	13.4	10.8	11.1	8.7	8.1	7.9	8.1	9.4	11.7	9.4	9.8	9.6
Duke Energy Corp.	DUK	1,313.1	1.84	22.6	18.1	22.5	22.4	25.0	34.2	29.0	23.2	23.5	26.1	25.3	28.0	26.8	18.5	15.0	12.2	11.8	10.6
Entergy Corp.	ETR	189.3	1.49	2.5	2.6	3.2	2.5	2.3	2.5	2.5	3.0	3.1	3.9	2.8	2.8	3.3	2.5	2.5	2.1	3.1	4.5
Exelon Corp.	EXC	660.6	2.30	15.6	14.7	12.4	10.5	11.1	11.0	8.6	8.1	8.2	7.3	9.3	13.6	12.5	13.1	9.5	8.7	7.6	6.0
FPL Group, Inc.	FPL	414.7	2.11	8.4	5.8	4.4	4.0	3.9	5.7	4.7	6.4	6.9	7.7	9.4	10.0	10.2	10.4	8.4	6.3	6.7	6.6
FirstEnergy Corp	FE	304.8	2.80	13.4	11.0	8.6	4.8	5.2	5.8	4.9	6.5	7.5	6.4	6.4	6.3	8.8	5.1	3.5	4.3	2.9	1.7
Great Plains Energy, Inc.	GXP	135.5	5.14	5.1	5.0	5.7	5.6	5.5	6.8	3.9	5.4	5.9	5.8	5.4	6.7	6.5	4.7	3.6	2.8	1.4	1.3
IDACORP, Inc.	IDA	48.1	5.76	1.9	1.9	1.9	2.2	1.9	1.7	2.1	1.8	1.8	1.8	1.8	2.0	1.9	2.0	2.0	1.9	1.9	2.1
MDU Resources Group, Inc.	MDU	188.1	0.34	0.5	0.6	0.6	1.0	1.1	1.3	1.4	1.0	0.8	1.6	2.6	2.6	3.1	2.8	1.9	1.6	1.5	1.7
NiSource, Inc.	NI	277.4	2.49	9.0	8.1	10.6	7.6	9.6	7.0	8.4	7.5	8.4	7.9	8.3	7.6	7.4	7.6	3.8	3.2	6.8	3.9
NorthWestern Corp.	NWE	36.2	3.92	1.8	2.4	1.5	1.9	1.6	2.1	2.5	2.3	1.6	1.4	1.7	1.2	1.3	1.1	1.3	1.2	0.9	2.7
PPL Corp.	PPL	378.6	0.99	4.9	2.3	2.5	1.7	2.1	2.6	2.8	3.5	4.2	3.6	3.7	4.0	5.4	6.5	5.5	6.1	6.4	5.8
Pepco Holdings, Inc.	POM	223.2	3.52	12.0	9.5	10.2	9.9	10.0	8.6	10.3	7.8	7.0	6.5	4.7	3.6	3.9	3.0	3.1	4.8	2.9	1.6
Pinnacle West Capital Corp.	PNW	108.4	1.15	1.8	1.9	2.6	2.4	2.7	2.7	3.5	3.5	3.9	4.5	5.7	5.0	4.4	4.4	4.6	3.4	2.9	2.7
Progress Energy, Inc.	PGN	287.2	1.65	4.1	3.8	7.0	5.6	4.5	5.3	5.6	6.0	7.6	7.7	7.3	7.2	7.0	7.6	7.7	6.1	5.3	4.4
Southern Company	SO	824.5	1.94	13.4	15.7	15.6	14.8	11.3	9.1	8.1	12.3	10.6	11.1	13.2	14.5	13.0	15.1	14.6	12.0	13.3	11.9
TECO Energy, Inc.	TE	213.9	1.01	2.8	2.7	3.5	4.2	5.3	8.6	7.2	6.2	5.2	3.5	3.6	3.4	4.0	3.5	3.8	2.5	3.7	3.8
Wisconsin Energy Corp.	WEC	116.9	1.66	2.3	2.6	3.3	3.9	3.2	2.6	1.9	2.0	3.2	4.2	2.9	3.1	2.8	3.7	4.3	3.9	4.4	4.1
Xcel Energy Inc.	XEL	459.6	2.70	8.4	8.5	10.3	9.7	9.7	8.1	9.5	8.3	10.9	11.5	10.9	10.9	13.7	13.8	11.8	8.3	5.3	5.8
Total		8,420.3		**214.8**	**200.1**	**205.3**	**191.8**	**198.2**	**214.4**	**201.8**	**193.9**	**199.3**	**204.6**	**207.3**	**215.4**	**211.9**	**204.0**	**182.6**	**165.2**	**165.9**	**151.9**

Source: Bloomberg (as of May 28, 2010)

UTILITIES INDUSTRY: DOWNGRADING DPL, UPGRADING CNL FOR LONG-TERM VALUE — *reprinted from 05/24/2010*

	Cur	Prv	Cur	Prv	FC	FC	Current EPS			Previous EPS		
Sym	Rtg	Rtg	Target	Target	2010	2011	2009	2010	2011	2009	2010	2011
CNL	BUY	HOLD	$30.00	NA	$2.11	$2.20	$1.73	$2.15	$2.20	$1.73	$2.15	$2.20
DPL	HOLD	BUY	NA	$30.00	$2.42	$2.58	$1.97	$2.40	$2.45	$1.97	$2.40	--

ACTION STATEMENT

We are downgrading our rating on shares of DPL to HOLD from BUY. We have become concerned that sustained weakness in power pricing will inhibit earnings growth. DPL has stable power pricing through 2012 under its Ohio rate plan. However, Ohio companies have seen increasing competition for customers as generators aggressively seek to market excess power capacity to spread fixed costs over volumes, at the expense of gross margin. **We are upgrading our rating on shares of CNL from HOLD to BUY given an attractive valuation when considering the long-term value of the Evangeline merchant generation assets.** We believe CNL management will successfully unlock the value of this efficient natural gas plant. In our view, current pricing offers a free call on this asset.

KEY INVESTMENT POINTS

Given an outlook for sustained weaker power prices and increasing customer shopping trends, we are less constructive on **DPL**. We are therefore downgrading shares to HOLD from BUY.

We are initiating a 2011 estimate for DPL of $2.45 and maintaining our 2010 estimate of $2.40. We note the 2011 First Call consensus estimate is $2.58 per share.

We recommend investors with longer-term time horizons put new money into CNL, given our view that current share pricing offers a free call option on the value of the 775 MW Evangeline merchant combined cycle plants.

We believe a conservative valuation of Evangeline to be roughly $4 per share, representing the lower portion of a valuation range of $300-$500 per installed kilowatt of capacity.

RISKS

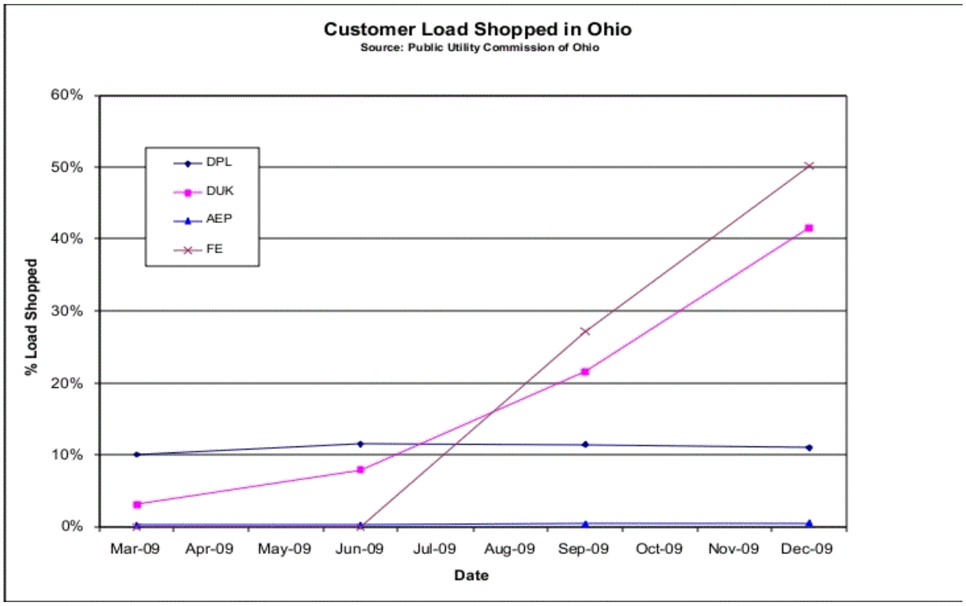
We believe the primary risk to our downgrade of DPL to be a rapid economic recovery driving increased demand and pricing of power. Regarding our upgrade of CNL, in our view the primary risk that could impede the stock from reaching our price target would be an inability to unlock the value of the Evangeline plants.

VALUATION

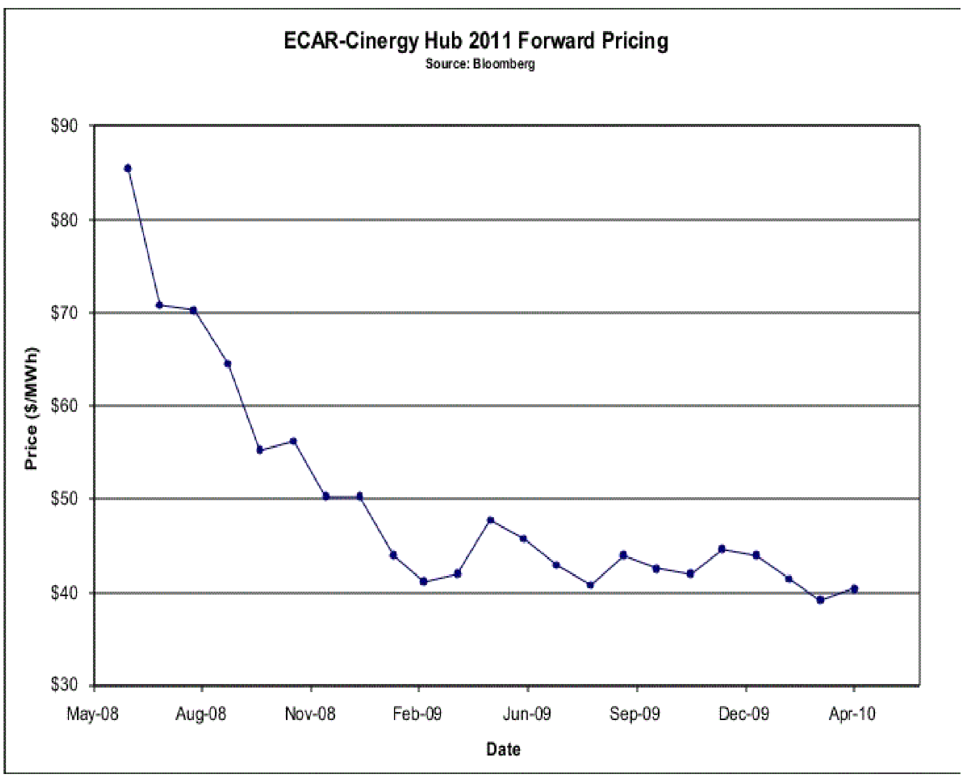
We believe DPL shares are close to fair value. Based upon our 2011 estimate, shares trade at a 9% discount to the peer group average P/E ratio of 11.28x. Given exposure to weak prices and risk of competition, we believe a 5-10% discount is reasonable and, with limited upside from current pricing, we are downgrading our rating on the shares to HOLD from BUY.

We believe CNL is most appropriately valued based on a sum-of-the-parts analysis since a simple P/E valuation fails to capture the value of merchant assets, which currently contribute no net income, but have intrinsic value. We believe the utility operations warrant a 5% premium valuation to the group average P/E. Based on our $2.20 per share 2011 estimate, this yields $26 per share of utility value. In our view, above average dividend growth, a record of achieving constructive regulation, consistent execution and outlook to produce meaningful free cash in the coming years make this premium appropriate. We value the merchant Evangeline asset at $300/kw, which yields approximately $4 per share of value. We are upgrading our rating on CNL shares from HOLD to **BUY** with a $30 price target. Our price target represents a P/E multiple of 13.6x our 2011 estimate vs. a current P/E of 11.9x and the peer group ratio of 11.28x.

We are downgrading our rating on DPL to **HOLD** from BUY. We have become less constructive on the name primarily due to a our view that power prices could remain weak for an extended period and, in a related concern, weak power demand could drive a continued increase in competition for customers, resulting in margin erosion. While DPL has largely been insulated from competitors entering its territory, we believe there is increased risk that as low hanging fruit has been captured in DPL's neighbors, competitors could increasingly target DPL's customers. The chart below illustrates shopping trends in Ohio.



Pricing for power remains weak. Prices have fallen approximately $4/MWh below DPL's forecast. Additionally, DPL's forecast for coal optimization has been negatively impacted by plant dispatch decisions of operating partners. The Midwest economy remains weak, which we expect could limit the appetite for near-term investment in efficiency and advanced metering, which we had viewed as a modest growth opportunity for the Company. Lastly, O&M costs have trended slightly higher. DPL reaffirmed its 2010 guidance of $2.35-$2.55. We remain comfortable in the lower portion of the range at $2.40 per share.



We are initiating a 2011 estimate of $2.45 per share. We view drivers to be modest load growth and fuel blending opportunities on the upside. We expect these will be partly offset by cost inflation, lower coal optimization opportunities and the potential for margin reduction driven by competition.

We recommend investors with a longer-term investment horizon consider CNL. We believe current pricing of the shares is compelling based upon a sum-of-the-parts valuation. In our view, current pricing offers a utility at a modest premium to the group average P/E, with a free call on Evangeline, the remaining unregulated generation assets (after the sale of Acadia Unit 2 to Entergy, which we expect to close in early 2011). Evangeline consists of a single 264 MW plant (Unit 6) and a 2 on 1 configuration 511 MW plant (Unit 7). Both are combined cycle with heat rates of 7360 and 7400, respectively.

We believe the asset value of Evangeline to be between $300 and $500/installed kw. We note the slightly more efficient (7160 heat rate) Acadia sold for $524/kw. We believe the value of the plant could be unlocked through an outright sale or through contracts to purchase power. Three large contracts totaling 900 MW will expire in March 2014, and we would expect that RFPs for new contracts would go out approximately one year earlier. One option CNL could bid into the RFP is the ratebasing of a portion or all of the Evangeline capacity. We believe Evangeline is well positioned to bid successfully into this RFP for several reasons:

- Evangeline is the last merchant combined cycle plant within Louisiana, offering more advantaged geographic proximity to the load.
- A weak natural gas strip bodes well if fuel costs enter the selection decision.
- NRG, which currently serves the existing contracts with its Big Cajun coal plant would likely need to include environmental retrofit costs into its offer.

In our view it was the upcoming visibility of these contract expirations that prompted CNL to restructure its Evangeline tolling agreement with JP Morgan. This contract originally committed the output of Evangeline to JP Morgan through 2020. Under the restructured agreement CNL takes the plant back in January 2012, unless JP Morgan exercises its option to extend the term by one year.

Previously, the Evangeline toll produced an estimated $0.10 per share of earnings for CNL, although we note it was non-cash. The toll is now expected to be earnings neutral until expiration. Investors reacted negatively to the restructuring. We believe this reaction was related to the fact that the transaction was dilutive, but the benefit of earlier ownership was not likely until 2014. We believe investors with a longer term horizon stand to benefit as management executes on realizing the value of the assets. In our view, management's track record of execution has been very solid including constructing the Rodemacher 3 plant on time and budget, monetizing the Acadia assets and successfully navigating the first rate case in over 20 years in a difficult economic environment.

PEPCO HOLDINGS, INC. (POM-NYSE) — HIGHLIGHTS FROM ANALYST CONFERENCE; ADJUSTING ESTIMATES — *reprinted from 05/14/2010*

Rating	HOLD
Price	$16.91
12-Mo. Price Target	NA
Dividend	$1.08
Yield	6.4%
52-Wk. Range	$12-$18
Trading Volume	2,700
Market Cap. (mm)	$3,760.1
Shares Out. (mm)	222.36
Book Value/Share	$18.72

Fiscal Year End	December
2011E	$1.20
2010E	$0.90
2009A	$0.91
2011 P/E	14.1x
2010 P/E	18.8x
First Call 2011E	$1.26
First Call 2010E	$1.16

Next Quarter	June
Estimate	$0.22
Vs.	$0.11
First Call Estimate	$0.24

ACTION STATEMENT

On May 13, 2010, Pepco Holdings, Inc. (POM-NYSE) held its Analyst Conference in Washington, D.C. Management introduced its 2010 earnings guidance, 2011 earnings outlook and its business plan to reposition POM predominantly as a regulated utility company. **We are adjusting our 2010 ongoing earnings estimate to $0.90 from $1.00 per share. We are also introducing our 2011 ongoing earnings estimate at $1.20 per share and maintain our HOLD rating.**

KEY INVESTMENT POINTS

"Repositioning PHI" [Pepco Holdings, Inc. (POM-NYSE)] was the theme at the Company's analyst meeting as management described its business plans to reposition POM primarily as a regulated transmission and distribution utility to lower the Company's business risk and earnings volatility and to strengthen its credit profile.

POM initiated 2010 ongoing earnings guidance at $0.80-$0.95 per share, indicating 2010 to be a "transition year" due to the planned sale of Conectiv Energy's merchant generation facilities.

2011 ongoing earnings outlook was introduced at $1.10-$1.30 per share based on higher retail distribution rates, 1% annual customer and sales growth, and interest cost savings from debt reductions, partly offset by higher operating and maintenance expense, higher depreciation and amortization expense, and reduced gross margins from the wind-down of the retail energy supply business.

At Power Delivery (the regulated utilities), management projects an 80% increase in total rate base to $8.563 billion over five years (through 2014) off a 2009 year-end base of $4.765 billion for a 12.4% CAGR.

Management reiterated its commitment to the current dividend of $1.08 per share. We discuss our takeaways from the analyst meeting below.

VALUATION

Based upon our 2011 estimate, POM trades at 14.1x P/E, compared to the group average P/E of 11.9x. We believe the 18.5% premium valuation is primarily due to the planned sale of the competitive generation business, an above-average 6.4% yield and generally favorable long-term demographics in attractive service territories. We view the current valuation as fully valued.

RISKS

We believe the primary risks are POM's large capital program of more than $5.4 billion over five years (through 2014), resulting in the need to frequently file for and receive constructive regulatory support in multiple state jurisdictions to minimize regulatory lag or an adverse outcome from IRS challenges to sale-in/lease-out (SILO) tax benefits that could potentially cost POM up to $875 million in taxes, penalties and interest due in a worst-case scenario of 100% disallowance.

DISCUSSION

POM hosted an analyst meeting on May 13, 2010 in Washington, D.C. In our view, the meeting topics and earnings outlooks were generally in line with investor expectations. We discuss our key takeaways from the analyst meeting below:

Repositioning to Predominantly a Regulated Utility

POM has begun to reposition its business mix to become predominantly a regulated transmission and distribution utility in an effort to lower the Company's business risk profile, reduce its earnings volatility and strengthen its credit profile. POM estimates its business mix for the competitive energy/other segments will fall to 5-10% of operating income by 2014, compared to a previous forecast of 25-30%. Correspondingly, POM expects about 90-95% of its operating income will come from the regulated utility segment by 2014 (compared to 70-75% previously forecast).

Much of the strategic repositioning will be accomplished with the sale of Conectiv Energy's merchant generation facilities to Calpine Corporation by mid-2010, completing the wind-down of the retail energy supply business at competitive Pepco Energy Services (PES) segment, and executing on more than $5.4 billion of planned regulated investments over the next five years in transmission and distribution infrastructure and AMI/Smart Grid "Blueprint for the Future" initiatives.

Sale of Conectiv Energy

On April 20, 2010, POM announced the sale of Conectiv Energy's competitive power generation facilities to Calpine Corporation for $1.7 billion (includes about $50 million in fuel inventory). Conectiv Energy's remaining non-core assets/contractual obligations (load service supply, energy portfolio hedges and certain tolling agreements) are expected to be liquidated through 1Q11, and together with the return of collateral and working capital, should result in about $350 million-$450 million in additional cash funds. After $300 million in estimated taxes, POM expects to use $1.75 billion in net proceeds from the transaction for parent debt reduction.

Management estimates the transaction will improve POM's credit profile to a mid-15% FFO/Debt ratio by 2011 (vs. 13% 2009 actual), lower its Debt/Capitalization ratio to 54% by 2011 (vs. 57% 2009 actual), and be modestly accretive to EPS in 2012. The sale also eliminates the need to issue any new equity until at least 2012 (excludes Dividend Reinvestment Plan equity issues of approximately $40 million annually).

Pepco Energy Services (PES)

The Company is on track with winding down its Retail Energy Supply (electric and natural gas) business and expects supply contracts to completely roll off by 2014. PES is now shifting its focus to growing its Energy Services business, which provides services and operational expertise to large customers in the areas of energy efficiency, renewable energy, and combined heat and power (CHP) plants. The Energy Services business has a goal to contribute earnings of $0.20 per share by 2014.

Power Delivery (Regulated Utilities) Construction Capital Spend Program

The regulated utilities plan to spend $5.461 billion on infrastructure investments over the next five years (through 2014), of which 42% is for transmission projects ($2.295 billion), 46% is for customer load and system reliability projects ($2.515 billion), and the remainder is for "Blueprint for the Future" utility initiatives and other projects. More than half ($1.309 billion) of the planned transmission projects have been granted a FERC-approved 150 basis point incentive ROE adder on top of the current 11.3% authorized ROEs.

The Mid-Atlantic Power Pathway (MAPP) transmission project is undergoing PJM's 2010 regional transmission expansion planning (RTEP) study, which should be completed in June 2010. The $1.2 billion MAPP project's current in-service date of June 2014 could be delayed by a year or two depending on the final results of the study. The CPCN (Certificate of Public Convenience and Necessity) procedural schedule for permitting the project in Maryland was temporarily suspended awaiting RTEP study completion. No construction activities are ongoing, although POM continues to move forward with environmental field reviews, engineering design and right-of-way acquisition activities. POM estimates major MAPP construction spending of $246 million will begin in 2011, compared to only $24 million budgeted in 2010.

"Blueprint for the Future" is a comprehensive program covering POM's utility initiatives to ultimately empower its customers to realize the benefits of managing their energy usage. These initiatives include Advanced Metering Infrastructure (AMI) and Smart Grid activities, energy efficiency and demand response programs, renewable energy and other distributed generation, and achieving constructive regulatory outcomes with respect to these programs through innovative rate structures and revenue decoupling. POM was awarded $168 million from the U.S. Department of Energy (DOE) in federal stimulus funds (American Reinvestment Recovery Act of 2009) for smart grid projects. From 2010-2014, POM plans to spend $402 million on AMI, which will be offset by $100 million in DOE funds. Another $277 million is forecasted to be spent on demand response, and energy efficiency programs will be offset by $36 million in DOE grants. $30 million in DOE reimbursements will be used to offset other capital expenditures related to distribution automation and system reliability.

2009 year-end rate base of $4.765 billion was comprised of approximately 76% distribution and 24% transmission investment. POM forecasts an 80% increase in total rate base to $8.563 billion over five years (through 2014) off the 2009 base for a 12.4% compounded annual growth in rate base. Electric distribution will account for 49% of rate base growth, while transmission investments will be responsible for 185% of rate base growth over this time period.

Dividend Outlook

Throughout the presentation, management continually reiterated its commitment to the current dividend of $1.08 per share. POM looks to move to a more typical industry dividend payout by growing earnings over the coming years.

Earnings Guidance and Assumptions

POM initiated 2010 ongoing earnings guidance at $0.80-$0.95 per share, indicating 2010 would be a "transition year" due to the planned sale of Conectiv Energy's merchant generation facilities. Primary earnings drivers in 2010 are expected to include rate case orders (Pepco MD, Delmarva Power DE, $20 million Atlantic City Electric settlement effective June 1) and 1% annual customer and sales growth, offset by operating and maintenance (O&M) expense, storm costs, depreciation expense and lower gross margins at the PES segment. 2010 pension/OPEB expense is expected to be $23 million (pretax) lower than 2009 (POM also plans to make a $100 million discretionary cash contribution to the pension plan).

POM's 2011 ongoing earnings outlook was introduced at $1.10-$1.30 per share. We believe the primary earnings assumptions behind the 2011 outlook include higher retail distribution rates, 1% annual customer and sales growth, growth in PES's Energy Services construction business and interest cost savings from debt reductions, partly offset by 3% higher O&M expense, higher depreciation and amortization expense, and reduced gross margins from the wind-down of the retail energy supply business at PES.

We are adjusting our 2010 ongoing earnings estimate to $0.90 from $1.00 per share, which excludes the earnings impact of Conectiv Energy sale as discontinued operations consistent with guidance. We are also introducing our 2011 ongoing earnings estimate at $1.20 per share.

Financing and Liquidity

Currently, consolidated POM has $1.159 billion in liquid credit facilities available. The Company has $791 million in short-term commercial paper and letters of credit outstanding, and long-term debt maturities of $498 million, $35 million and $750 million due in 2010, 2011 and 2012, respectively. Of these amounts, the parent holding company has $631 million in short-term credit facilities outstanding and long-term debt maturities of $450 million in 2010 and $750 million in 2012.

As discussed earlier, POM plans to apply $1.75 billion in net proceeds from the sale of Conectiv Energy for short-term and long-term parent debt reduction. While the exact amounts to be applied to the parent credit facilities and/or the large 2012 maturity have yet to be determined, they are likely to be in the magnitude of several hundred million dollars for each. The sale also eliminates the need to issue any new equity until at least 2012 (excludes Dividend Reinvestment Plan equity issues of approximately $40 million annually). POM expects to issue new long-term debt at the utilities of $200 million-$300 million in 2011.

Going forward post-2011, POM is targeting to have credit metrics of over 15% FFO/Debt coverage ratio (vs. 13% 2009 actual), around a 55% Debt/Capitalization ratio (vs. 57% 2009 actual), and for FFO/Interest coverage ratio of 3.5x.

Cross-Border Energy Lease Update

POM expects to begin the litigation process mid-year 2010 in the Federal Court of Claims against the IRS disallowing tax benefits from sale-in lease-out (SILO) transactions. In the meantime, POM is required to make a tax payment of $77 million, plus $45 million in penalties and interest on 2001/2002 audited tax returns that are currently in appeals. POM would sue for a refund of these payments through the litigation process, which could take up to two years to resolve from the time of filing.

Currently, POM realizes annual tax benefits of approximately $59 million and net earnings benefits of approximately $22 million from its existing SILO cross-border energy lease investments.

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	$0.17	-65.3%	$0.16A	-5.9%	--	--
2Q	$0.11	-79.2%	$0.22	100.0%	--	--
3Q	$0.44	-25.4%	--	--	--	--
4Q	$0.18	-43.8%	--	--	--	--
YEAR	$0.91	-52.8%	$0.90	-1.1%	$1.20	33.3%

Source: KeyBanc Capital Markets Inc. estimates
Note 6: 2009 Q1: includes $0.02 incremental loss vs 1Q08 due to prior period income tax adjustment under FIN-48
Note 7: 2009 Q2: includes $0.05 incremental loss vs 2Q08 due to prior period income tax adjustment under FIN-48
Note 8: 2010 Q1: POM reported 1Q10 ongoing EPS of $0.16. We exclude $0.04 for severe winter storm restoration costs and $0.04 for Conectiv Energy earnings due to 4/20/2010 announced sale and reclassification to discontinued operations.

DOMINION RESOURCES, INC. (D-NYSE) — ANALYST DAY HIGHLIGHTS — *reprinted from 05/12/2010*

Rating	HOLD
Price	$41.80
12-Mo. Price Target	NA
Dividend	$1.75
Yield	4.2%
52-Wk. Range	$30-$43
Trading Volume	3,433
Market Cap. (mm)	$25,025.7
Shares Out. (mm)	598.70
Book Value/Share	$18.97

Fiscal Year End	December
2011E	$3.25
2010E	$3.30
2009A	$3.27
2011 P/E	12.9x
2010 P/E	12.7x
First Call 2011E	$3.25
First Call 2010E	$3.27

Next Quarter	June
Estimate	$0.61
Vs.	$0.68
First Call Estimate	$0.65

ACTION STATEMENT

Dominion (D-NYSE) hosted a well attended analyst meeting where its 2010 earnings outlook was reaffirmed, 2011 guidance introduced and a long-term growth rate of 5-6% was established (once commodity markets have stabilized). We believe the presentation was generally well received.

KEY INVESTMENT POINTS

Dominion held its analyst day on May 7 in New York City. We discuss takeaways from the meeting below.

Dominion reaffirmed 2010 guidance of $3.20-$3.40 per share. 2011 earnings guidance was introduced at $3.10-$3.40.

Management endorsed a long-term growth rate of 5-6%. The growth rate is based on the assumption that commodity markets would see some pricing recovery.

We are maintaining our 2010 estimate of $3.30 and introducing a 2011 estimate of $3.25 per share.

VALUATION

Based upon our 2011 estimate, shares of Dominion's stock sell at a P/E multiple of 12.9x, which represents a 9% premium to the group average multiple of 11.8x. Given a favorable Virginia settlement, which would present a stable regulatory environment and reduced commodity exposure after portfolio realignment, and a primarily regulated investment pipeline, we view shares as essentially fairly valued.

RISKS

We believe the primary risks to Dominion to be any effort to revisit Virginia utility regulation and sustained weakness or further weakness of commodity pricing.

DETAILS

Dominion hosted an investor conference on May 7 in New York City. In our view, the meeting was generally upbeat and well received by investors. Below are the key takeaways from the meeting:

Earnings Outlook – Dominion management reaffirmed its prior 2010 outlook for EPS of $3.20-$3.40. 2011 guidance of $3.10-$3.40 was introduced. Dominion foresees an average long-term growth rate of 5-6%. This growth rate is expected to be challenged in the near term until commodity prices see a rebound. From a business mix perspective, Dominion acknowledged that the unregulated side of the business was likely to face headwinds in the current commodity environment. On the regulated side, we believe management is fairly confident that it can earn near the top of its VEPCO base rate ROE band, without tripping the two-year average ROE of 12.4%, which could open a rate proceeding. This test is based upon GAAP earnings.

Dividend Outlook – Management has targeted an earnings mix of 65-75% regulated earnings. Fifty-eight percent of 2009 earnings were from regulated businesses. Dominion also indicated that with the move in earnings composition more toward regulated earnings, it would recommend to the Board raising the dividend payout ratio from 55% to a range of 60-65% of earnings.

Capital Program – Dominion expects to invest $10.9 billion through 2012. Of this total, 83% will be spent on regulated operation. The balance to be spent at unregulated subsidiaries will be focused on environmental and nuclear fuel. $5.9 billion of the total is to be directed to growth (99% of the growth is for regulated businesses), $3.0 billion on maintenance capital, $1 billion on environmental equipment and $0.96 billion for nuclear fuel. Dominion also noted that of the $10.9 billion of planned capex, approximately $4 billion is covered under riders.

Breaking the forecast growth spend by business: VEPCO's capital program is roughly $4.5 billion (with $550 million/year on FERC-regulated transmission); Regulated natural gas operations would spend $1.5 billion on regulated infrastructure.

Cost Control – Dominion's forecast is premised upon achieving O&M savings and fuel management benefits of $250 million annually. This is comprised of $100 million related to Dominion's recent 7% (1,200 FTEs) headcount reduction, more than $40 million from salary freezes with the balance coming from reassessing all expenses and fuel optimization. Additionally, lower dispatch of merchant plants will reduce O&M spending. Fifty percent of these costs are estimated to be derived from VEPCO.

Use of Marcellus Proceeds – On March 15, Dominion announced the sale of its Marcellus reserves to Consol for $3.475 billion. At its meeting, Dominion discussed how it planned to use the aftertax proceeds of $2.28 billion. $400 million of 2010 equity issuances will be avoided, $250 million will be used to paydown debt, $220 will fund obligations under VEPCO's settlement, $250 million will be contributed to the pension plan, $250 million will offset 2011 equity market issuances and $910 million to repurchase stock (of which around $500 million has been used in the past 60 days).

Financing Plans – As indicated above, Marcellus proceeds will offset market equity offerings in 2010 and 2011. Dominion may reinstate its DRIP program in 2011. Dominion indicated a strong cash position could reduce planned debt issuances of $1.6 billion in 2010. In 2011 and 2012, Dominion expects to be cash flow negative.

Merchant Outlook – Dominion discussed the impact of low commodity pricing on its unregulated operation, particularly its NEPOOL (New England) assets. Dominion's Midwest assets have longer dated contracts. In NEPOOL, Dominion is approximately 90% hedged in 2010, 36% hedged in 2011 and approximately 20% in 2012. Dominion expects commodity prices could rebound in the 2012 period. Dominion does not believe renewable imports will have a material impact in New England. Dominion is considering retirement of some of its unscrubbed New England Coal capacity, Salem 1 and 2.

New Nuclear Outlook – Dominion indicated that it had chosen Mitsubishi Heavy Industries technology if it goes ahead with plans to build a new nuclear plant. This follows a breakdown of negotiations with GE. The plant would be 1,500 MW. At this juncture, Dominion believes if it builds the plant itself, it would likely push the plant timing out. Dominion is also considering taking on a partner. The options to abandon or build the plant alone now are considered unlikely. Dominion appeared to us to be pleased with the risk-sharing concessions it was able to achieve in discussions.

As discussed, we believe investors were generally pleased with Dominion's strategy of focusing capital and management resources on regulated investment, particularly with FERC-regulated transmission and Virginia investment receiving constructive levels of return. We believe investors have come to accept Dominion's merchant exposure, which management has reduced to a level below many of Dominion's peers. In our view, commodity pricing may be close to troughing, although the length of the trough remains a potential concern for many.

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	$0.97	-3.0%	$0.96A	-1.0%	--	--
2Q	$0.68	36.0%	$0.61	-10.3%	--	--
3Q	$0.99	5.3%	--	--	--	--
4Q	$0.63	-12.5%	--	--	--	--
YEAR	$3.27	3.5%	$3.30	0.9%	$3.25	-1.5%

Source: KeyBanc Capital Markets Inc. estimates

CENTRAL VERMONT (CV-NYSE) — SHARE WEAKNESS UNWARRANTED, COSTS RECOVERABLE — *reprinted from 05/10/2010*

Rating	HOLD
Price	$20.50
12-Mo. Price Target	NA
Dividend	$0.92
Yield	4.5%
52-Wk. Range	$16-$23
Trading Volume	47
Market Cap. (mm)	$241.1
Shares Out. (mm)	11.76
Book Value/Share	$19.77

Fiscal Year End	December
2011E	$1.70
2010E	$1.60
2009A	$1.74
2011 P/E	12.1x
2010 P/E	12.8x
First Call 2011E	$1.85
First Call 2010E	$1.64

Next Quarter	June
Estimate	$0.40
Vs.	$0.46
First Call Estimate	$0.38

ACTION STATEMENT

Central Vermont Public Service Corporation (CV-NYSE) reported 1Q results that were lower than consensus. However, the items driving reduced results are ultimately recoverable from ratepayers and the expenses are expected to be reversed later in the year.

KEY INVESTMENT POINTS

On May 6, CV announced 1Q10 EPS of $0.35 vs. $0.58 in the prior-year period. This is below our $0.38 estimate and consensus of $0.50 per share.

While we had contemplated the $0.16 per share impact of severe winter storms, our estimate did not include the $0.06 per share charge related to healthcare legislation. We note that under CV's rate plan, we expect these items to be treated as "exogenous events," and are therefore recoverable when in excess of $600,000.

We believe CV's trading weakness after reporting is related to the headline number, which was below consensus (of two estimates), without regard to the fact the above items will largely be reversed in 4Q10.

We are maintaining our 2010 estimate of $1.60 per share and introducing a 2011 estimate of $1.70 per share.

VALUATION

Based upon our 2011 estimate, shares of CV stock trade at a P/E multiple of 12.1x, compared to the group average P/E multiple of 11.4x. We believe shares are modestly attractive to fairly valued at current levels and maintain our **HOLD** rating.

RISKS

We believe the primary risk to CV is any deterioration in the Vermont regulatory landscape, which we believe has improved through the implementation of CV's current Alternative Regulation Plan, which lasts through 2011. Additionally, CV is exposed to potential impacts of weather, major storms and prolonged economic weakness affecting retail usage.

DISCUSSION

On May 6, after the market close, CV reported 1Q10 EPS of $0.35. Results were below expectations. We believe the consensus estimate of $0.50 did not fully contemplate two items: $0.16 of storm damages and a $0.06 charge related the healthcare legislation. CV's regulatory plan allows recovery of exogenous factors above a value of $600,000. We expect these two 1Q items to be largely reversed in 4Q10. CV traded weakly following the report, and we believe this was related to missing consensus without proper regard for the fact the costs are recoverable and will be reversed.

We are maintaining our 2010 estimate of $1.60 and introducing a 2011 estimate of $1.70. Drivers of 2011 growth are incremental investment earning a return under CV's recovery mechanisms and modest accretion from CV's recently announced acquisition of Vermont Marble, partly offset by a higher share count from the sale of shares.

1Q REVIEW

Warmer than normal weather drove reduced retail sales of -3.0% (Residential -4.8%, Commercial -2.5% and Industrial +1.2%). Other factors in the quarter included: higher equity in earnings of affiliates related to incremental investment (+$0.05); higher operating revenues (+$0.01); storm costs (-$0.16); higher non-storm expenses (-$0.06); Medicare Part D charge (-$0.06); transmission expense (-$0.02); higher purchased power costs (-$0.01); and other (+$0.02).

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	$0.58	3.6%	$0.35A	-39.7%	--	--
2Q	$0.46	21.1%	$0.40	-13.0%	--	--
3Q	$0.52	-14.8%	--	--	--	--
4Q	$0.18	NM	--	--	--	--
YEAR	$1.74	14.5%	$1.60	-8.0%	$1.70	6.2%

Source: KeyBanc Capital Markets Inc. estimates

AVISTA CORPORATION (AVA-NYSE) — 1Q10 - MILD WEATHER AND WEAK HYDRO; LOWERING ESTIMATE — *reprinted from 05/06/2010*

Rating	HOLD
Price	$20.72
12-Mo. Price Target	NA
Dividend	$0.84
Yield	4.1%
52-Wk. Range	$15-$22
Trading Volume	242
Market Cap. (mm)	$1,141.7
Shares Out. (mm)	55.10
Book Value/Share	$19.17

Fiscal Year End	December
2011E	$1.80
2010E	$1.55
2009A	$1.58
2011 P/E	11.5x
2010 P/E	13.4x
First Call 2011E	$1.83
First Call 2010E	$1.66

Next Quarter	June
Estimate	$0.49
Vs.	$0.47
First Call Estimate	$0.55

ACTION STATEMENT

Avista Corporation (AVA-NYSE) reported results below expectations as the Company was adversely impacted by very mild weather, low precipitation and weak hydro output. Residential electric and gas usage declined 11% and 21%, respectively. Management indicated poor conditions hurt results by an estimated $0.10-$0.15 per share. We have reduced our 2010 EPS estimate to $1.55 from $1.70. We have introduced a 2011 EPS estimate of $1.80.

KEY INVESTMENT POINTS

On May 6, AVA reported EPS of $0.52 vs. $0.57, below our estimate and consensus, which were $0.56. The quarter was impacted by very mild weather and poor hydro conditions.

Driven by warmer weather, residential electric and natural gas demand declined 11% and 21%, respectively. On a weather normalized basis, demand declined modestly.

Management reaffirmed 2010 guidance of $1.55-$1.75. However, given that the 1Q is generally AVA's strongest quarter, management indicated earnings would probably be at the low end of guidance.

We have reduced our 2010 estimate from $1.70 to $1.55. We are also introducing a 2011 estimate of $1.80.

VALUATION

Based upon our 2011 estimate of $1.80, AVA shares sell at an 11.5x P/E multiple, close to the group average P/E of 11.6x. We believe this is reasonable and maintain our **HOLD** rating on the shares.

RISKS

We believe the primary risks facing AVA are ongoing financial exposure to variable hydro conditions and the need to file frequent rate cases.

DISCUSSION

AVA reported 1Q10 EPS of $0.52 vs. $0.57 in the prior-year period. Results were below expectations of $0.56. Results were negatively impacted by poor hydro conditions and very warm weather that reduced heating demand. As a result, utility earnings declined to $0.50 from $0.56. Results were also lowered by absorption of energy supply costs of $1.2 million, while the prior-year period included a $2.7 million benefit under the energy recovery mechanism (ERM). These items were partially offset by new rates in Washington and Oregon.

At Advantage IQ (the bill processing business), results improved to $0.03 from $0.02. The 2009 acquisition of Ecos drove a 38% increase in revenues. AVA indicated that excluding the acquisition, earnings would have been flat to slightly up. The other segment had flat results of a $0.01 per share loss.

Management indicated that poor 1Q10 conditions had cost an estimated $0.10-$0.15 per share vs. plan. As such, AVA now expects full year results to fall at the low end of 2010 guidance of $1.55-$1.75 per share. While poor hydro conditions are expected to result in hydro generation levels at 81% of normal, AVA still expects to benefit under the ERM mechanism, as power and natural gas prices are below where the forward strip was when rates were set in the last Washington rate case. This forecast was premised on $5.60/dkthm natural gas.

We have reduced our 2010 estimate to $1.55 per share. We are also introducing a 2011 estimate of $1.80 per share. The increased earnings are driven by a return to more normal conditions and incremental capital being reflected in upcoming rate cases, partly offset by a higher share count after an expected $45 million equity offering in 2010.

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	$0.57	21.3%	$0.52A	-8.8%	--	--
2Q	$0.47	6.8%	$0.49	4.3%	--	--
3Q	$0.11	37.5%	--	--	--	--
4Q	$0.44	37.5%	--	--	--	--
YEAR	$1.58	20.6%	$1.55	-1.9%	$1.80	16.1%

Source: KeyBanc Capital Markets Inc. estimates

CENTRAL VERMONT PUBLIC SERVICE CORPORATION (CV-NYSE) — QUICK ALERT: SMALL TRANSACTION APPREARS MODESTLY ACCRETIVE — *reprinted from 05/06/2010*

- Central Vermont Public Service Corporation (CV-NYSE) recently announced the proposed acquisition of Vermont Marble for $33.2 million. This adds 890 customers, including Omya Inc., which would become CV's largest customer (about 10% of CV's load). Vermont Marble is surrounded by CV's service territory.

- Omya is a producer of calcium carbonate (used in paper, plastics and paint). Because the plant is on top of mineral reserves, we believe the plant is not likely to relocate.

- Included are the transmission and distribution assets to serve the town of Proctor, Vt., as well as 18 MW of hydro capacity.

- We understand that the hydro will require approximately $12 million of maintenance and uprates, offering CV an incremental investment opportunity. Replacing a substation is another $1.5 million investment opportunity.

- Based upon our analysis, we foresee modest accretion of $0.01-$0.02 per share. We assume that the transaction is financed with a 50/50 capital structure. The transaction is expected to close by year-end. Higher initial accretion could be realized if equity financing occurs after close, although we believe it would be fairly soon after the close.

- This transaction requires FERC and the Vermont Public Service Board (PSB) approval, neither of which we expect to be an issue. In fact, we would expect the PSB to be supportive of the transaction in light of the efficiency gains and potential improvement in customer service (Vermont Marble has no line crews). We believe the transaction could actually garner regulatory good will.

GREAT PLAINS ENERGY INCORPORATED (GXP-NYSE) — PRICE TARGET ACHIEVED, REDUCING RATING TO HOLD — *reprinted from 05/04/2010*

Rating	HOLD
Price	$19.63
12-Mo. Price Target	NA
Dividend	$0.83
Yield	4.2%
52-Wk. Range	$13-$20
Trading Volume	757
Market Cap. (mm)	$2,677.5
Shares Out. (mm)	136.40
Book Value/Share	$20.68

Fiscal Year End	December
2011E	$1.65
2010E	$1.35
2009A	$1.14
2011 P/E	11.9x
2010 P/E	14.5x
First Call 2011E	$1.68
First Call 2010E	$1.35

Next Quarter	March
Estimate	$0.10
Vs.	$0.18
First Call Estimate	$0.09

ACTION STATEMENT

With Great Plains Energy (GXP-NYSE) having traded through our prior $19.50 per share price target, we are now reducing our rating on the shares from BUY to **HOLD**. We are also introducing a 2011 estimate of $1.65 per share.

KEY INVESTMENT POINTS

With shares of GXP's stock trading above our prior price target, we are reducing our rating on the shares to **HOLD** from BUY. We previously had a $19.50 price target on GXP.

We are also introducing our 2011 estimate of $1.65 per share. The notable uptick vs. our 2010 estimate of $1.35 is due to the Iatan 2 plant coming into rates.

We assume new rates will become effective at year-end 2010 in Kansas and in the early part of 2Q11 in Missouri, consistent with management's recent project update.

Management recently provided an update on Iatan 2 construction, which included a shift in the operational date of Iatan 2 from late summer 2010 to fall 2010, and a modest increase in the project cost.

VALUATION

Based upon our 2011 estimate, shares of GXP sell at a P/E multiple of 11.9x, which is a modest discount to the group average P/E ratio of 12.1x. We view this as reasonable and therefore consider a **HOLD** rating appropriate.

RISKS

We believe the risks to GXP shares would be an inability to achieve a fair and timely regulated return on capital investments, exposure to unplanned outages that could impact results given the lack of a fuel pass-through mechanism in Missouri (at KCP&L operations; KCPL-GMO utilities have a fuel clause) and a prolonged economic downturn during which the Company must fund its significant capital program.

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	$0.18	100.0%	$0.10	-44.4%	--	--
2Q	$0.28	12.0%	--	--	--	--
3Q	$0.57	-35.2%	--	--	--	--
4Q	$0.11	37.5%	--	--	--	--
YEAR	$1.14	-16.8%	$1.35	18.4%	$1.65	22.2%

Source: KeyBanc Capital Markets Inc. estimates
Note 2: 2009 Annual: GAAP Earnings

DTE ENERGY COMPANY (DTE-NYSE) — 1Q10 STRONG QUARTER, RAISING ESTIMATES —
reprinted from 04/29/2010

Rating	HOLD
Price	$48.29
12-Mo. Price Target	NA
Dividend	$2.12
Yield	4.4%
52-Wk. Range	$29-$48
Trading Volume	1,133
Market Cap. (mm)	$8,016.1
Shares Out. (mm)	166.00
Book Value/Share	$37.34

Fiscal Year End	December
2011E	$3.75
2010E	$3.60
2009A	$3.30
2011 P/E	12.9x
2010 P/E	13.4x
First Call 2011E	$3.68
First Call 2010E	$3.50

Next Quarter	June
Estimate	$0.77
Vs.	$0.56
First Call Estimate	$0.60

ACTION STATEMENT.

We are raising our 2010 estimate for DTE Energy (DTE-NYSE) to $3.60 from $3.50 per share for improving electric margins, cost savings, and 1Q strength in Power & Industrial Projects and Energy Trading segments. We are also introducing our 2011 estimate at $3.75 per share. Shares of DTE trade at 12.9x our 2011 estimate compared to the 2011 group average P/E ratio of 12.0x. We believe a modest premium is reasonably valued and maintain our **HOLD** rating.

KEY INVESTMENT POINTS

DTE reported 1Q10 operating earnings of $1.38 vs. $1.10 per share, well ahead of First Call consensus of $1.20 and our high on the Street estimate of $1.30 per share.

Overall, 1Q10 earnings improved, as the electric and gas utilities benefitted from new rates in effect and a slowly recovering Michigan economy, non-utility Power & Industrial Projects segment earnings were higher on coke sales to the steel industry and new projects coming online, and Energy Trading performance remained strong.

DTE raised 2010 EPS guidance to $3.45-$3.80 from $3.35-$3.75.

We are raising our 2010 earnings estimate to $3.60 from $3.50 per share for improving electric margins and load trends, cost savings, and 1Q strength in Power & Industrial Projects and Energy Trading segment results.

We are introducing our 2011 estimate at $3.75 per share. DTE management reiterated the Company's growth plan to achieve a long-term average annual operating earnings growth target of 5-6%.

VALUATION

Based upon our 2011 estimate, shares of DTE trade at 12.9x compared to the 2011 group average P/E ratio of 12.0x, which we view as reasonable.

RISKS

We believe the primary risks to DTE shares are a slowly recovering Michigan economy regressing back to a persistent weakened state, continued weak gas prices limiting Unconventional Gas (E&P) segment development and monetization opportunities, and any deterioration from a supportive regulatory climate in Michigan.

DISCUSSION

DTE raised 2010 operating earnings guidance to $3.45-$3.80 from $3.35-$3.75 per share. DTE management expressed confidence in the midpoint of guidance at $3.63 per share during the earnings conference call. Primary drivers for the increased guidance were higher full-year electric load projections (+2% in 2010 vs. +1% prior view), improving margins at the electric utility from new rates (including a decoupling mechanism) and continuous improvement in cost savings, an industrial rebound in the steel sector and new projects coming online strengthening results at the Power & Industrial Projects segment, strong 1Q Energy Trading performance, and lower taxes at Corporate parent.

We are raising our 2010 earnings estimate to $3.60 from $3.50 per share for improving electric margins and load trends, continued cost savings, and 1Q strength in Power & Industrial Projects and Energy Trading segment results. DTE is beginning to see signs of an economic recovery in Michigan, led by the automotive and steel sectors. Temperature-normalized sales increased 2% year-over-year, led by industrial-sector load improvement of 12%. The Company now forecasts an industrial load rebound of 13% this year vs. 9% prior view. Sustainable operating and maintenance (O&M) cost reductions in 2010 are targeted for $60 million to help offset inflationary pressures.

We are introducing our 2011 estimate at $3.75 per share. DTE management reiterated the Company's growth plan to achieve a long-term average annual operating earnings growth target of 5-6%. We review each of the investment areas below:

- Over the next three years (2010-2012), Detroit Edison electric utility plans to spend $300 million-$400 million on renewable energy investments, $500 million-$600 million to meet environmental requirements at major coal plants, $2.1 billion-$2.3 billion on base infrastructure generation and distribution reliability investments, and $100 million on energy optimization/efficiency investments to meet state RPS mandates.
- MichCon gas utility plans to spend $400 million-$500 million on base infrastructure and growth projects from 2010-2012 .
- Gas Storage and Pipelines segment sees growth opportunities to take advantage of Marcellus shale gas flows. Previously, DTE has mentioned growth opportunities in the Vector pipeline in the Midwest, Millennium pipeline in the Northeast, and continued development of gas storage in Michigan.
- Power & Industrial Projects segment continues to see near-term growth opportunities throughout the United States, predominantly in renewable energy acquistions to convert small coal-fired plants to biomass power plants to meet various state RPS standards and qualify for renewable energy credits.
- Unconventional Gas (E&P) segment plans to prudently manage its costs and optimize production of its Barnett Shale assets. Due to low gas commodity prices, capital investments in this segment will be about $25 million in 2010 to drill 10-15 wells and produce 5 Bcfe natural gas.

1Q10 REVIEW

DTE reported 1Q10 operating earnings of $1.38 vs. $1.10 per share, well ahead of First Call consensus of $1.20 and our high on the Street estimate of $1.30 per share. GAAP reported earnings were $1.38 vs. $1.09 per share. We had highlighted DTE as an upside surprise in our quarterly earnings preview. Relative to our expectations, Energy Trading segment results were stronger, while MichCon gas utility showed less improvement than we had anticipated due to warm winter weather and customer conservation.

Overall, 1Q10 earnings improved as the electric and gas utilities benefitted from new rates in effect in January (gas rates were interim self-implemented) and a slowly recovering Michigan economy, non-utility Power & Industrial Projects segment earnings were higher on coke sales to the steel industry and from new projects coming online, and Energy Trading performance remained strong.

BELOW, WE HIGHLIGHT 1Q10 RESULTS BY SEGMENT:

Utility Segments:

- Detroit Edison (electric utility) had higher operating earnings of $0.55 vs. $0.48 in 1Q09 due to rate increases and cost savings, partially offset by higher depreciation, property taxes, interest expense and benefit expenses. Total sales were essentially flat; however, weather-adjusted sales volumes were up 2% year-over-year on an improving economy (Weather adjusted territory sales: Residential +1%, Commercial -3%, Industrial +12%, Other -2%).
- MichCon (gas utility) reported $0.48 vs. $0.37 due to new self-implemented interim rates and cost savings, partially offset by unfavorable warmer winter weather, customer conservation, lower midstream revenues, higher taxes and higher interest expense.

Non-Utility Segments:

- Gas Storage and Pipelines reported $0.08 vs. $0.09 in 1Q09 with the EPS decline due to share dilution.
- Unconventional Gas Production (E&P) had a $0.02 loss vs. a $0.01 loss in 1Q09.
- Power and Industrial Projects (including coal services) had earnings of $0.11 vs. $0.02 in 1Q09 on higher coke sales to the steel industry and new projects coming online.
- Energy Trading had earnings of $0.23 vs. $0.24 in 1Q09. Unrealized mark-to-market gains were $0.17 vs. $0.20 in 1Q09. 1Q09 trading results were viewed as robust.
- Corporate and Other improved to a $0.05 loss vs. a $0.09 loss in 1Q09 primarily due to lower one-time Michigan tax benefit where DTE was allowed to release a booked reserve.

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	$1.10	41.0%	$1.38A	25.5%	--	--
2Q	$0.56	250.0%	$0.77	37.5%	--	--
3Q	$0.91	-14.2%	--	--	--	--
4Q	$0.72	-18.2%	--	--	--	--
YEAR	$3.30	13.8%	$3.60	9.1%	$3.75	4.2%

Source: KeyBanc Capital Markets Inc. estimates

PPL CORPORATION (PPL-NYSE) — QUICK ALERT: PPL TO ACQUIRE E.ON U.S. ASSETS — *reprinted from 04/28/2010*

April 27, 2010 Close: $25.60
1Q10 KBCM Estimate $0.92 (Consensus $0.86)
2010 KBCM Estimate $3.25 (Consensus $3.33)
PPL Pre-released 1Q10 ongoing results of $0.94 vs. $0.60 and GAAP results of $0.66 vs. $0.64 per share.

- PPL announced the purchase of Louisville Gas & Electric and Kentucky Utilities from German utility E.ON for $7.2 billion, excluding acquired tax benefits of $450 million.
- Financing is to be accomplished with equity, first mortgage bonds, corporate debt and "high-equity-content securities". Additionally, PPL indicated that it could raise capital through the divestiture of non-core assets.
- PPL has indicated that the deal will be modestly dilutive in 2011 and accretive in 2013. Our initial analysis of the much rumored deal suggested that the deal could be roughly $0.20-$0.30 dilutive to consensus 2011 EPS of $3.20, using a 50/50 financing structure. We expect using hybrid securities could reduce dilution.
- PPL indicated that the transaction will reduce the Company's risk profile through deriving a higher proportion of earnings through more stable regulated earnings as opposed to more commodity driven unregulated generation.
- Rumors had circulated that DUK, AEP, SO and private equity investors were looking at the deal. DUK and AEP had the advantage of geographic contiguity, offering enhanced synergy potential, which likely could have lead to a higher bid for the assets. Additionally, the larger balance sheets of these entities could likely have more easily absorbed this transaction.
- In our view, PPL has reacted defensively to a weak electricity pricing market and forward curve, the duration of which has become increasingly uncertain given the unknowns around the timing of the return of pre-recession power demand and the impact of prolific shale based supplies of natural gas. In our view, prolonged commodity pricing weakness would leave PPL exposed in 2013, when hedges put on in more favorable markets expire.

We expect that key takeaways from the 8:00 EDT conference call (888-396-2386; Passcode: PPL) will focus on:

1. Financing structure, particularly the level of hybrid securities to be utilized.
2. Outlook for synergies, net of sharing with ratepayers.
3. What level of 2013 earnings were assumed in the statement that the transaction is expected to turn accretive that year.
4. Potential candidates for asset divestiture, as PPL has largely divested non-core assets.

SOUTHERN COMPANY (SO-NYSE) — WEATHER DRIVES STRONG QUARTER, ECONOMY SHOWING POSITIVE SIGNS — *reprinted from 04/28/2010*

Rating	HOLD
Price	$35.26
12-Mo. Price Target	NA
Dividend	$1.82
Yield	5.2%
52-Wk. Range	$27-$35
Trading Volume	3,928
Market Cap. (mm)	$28,560.6
Shares Out. (mm)	810.00
Book Value/Share	$17.95

Fiscal Year End	December
2011E	$2.50
2010E	$2.40
2009A	$2.32
2011 P/E	14.1x
2010 P/E	14.7x
First Call 2011E	$2.51
First Call 2010E	$2.35

Next Quarter	June
Estimate	$0.58
Vs.	$0.61
First Call Estimate	$0.6

ACTION STATEMENT

Southern Company (SO-NYSE) reported a strong quarter driven by cold weather, O&M timing and economic improvement. Early signs suggest that SO's service territory could be in the midst of a recovery. However, management has conservatively not raised guidance, as it waits until it has the opportunity to assess further data points. We have raised our 2010 estimate above guidance and introduced a 2011 estimate.

KEY INVESTMENT POINTS

SO reported 1Q10 ongoing earnings of $0.60 vs. $0.42 per share, ahead of our $0.45 estimate, guidance of $0.42, and consensus of $0.44.

Driving results were very cold weather, economic improvement (particularly in the industrial sector), O&M timing and a tax item.

With SO's robust 1Q10 results, we are raising our 2010 estimate to $2.40 per share from $2.35. Management maintained its prior guidance range of $2.30-$2.36 per share. We are also introducing a 2011 estimate of $2.50 per share.

In the 1Q, SO's retail sales improved 10.3%, largely due to weather. However, of note is the fact that industrial sales, which are generally insensitive to weather, improved 6.7%.

VALUATION

Based upon our 2010 estimate, shares of SO stock sell at a P/E ratio of 14.7x, representing a 13% premium to the group average. Given a historical trading premium, we believe shares are fairly valued to modestly attractive and maintain our **HOLD** rating on SO.

RISKS

We believe the primary risks to SO would be a reversal of traditional constructive Georgia regulation in the Company's upcoming rate case and a worsening economy after recent signs of improvement.

DISCUSSION

On April 28, SO reported 1Q10 earnings of $0.60 vs. $0.18 per share. Excluding a $0.26 1Q09 litigation settlement, operating results were $0.60 vs. $0.42. Results were well above our $0.45 estimate and consensus of $0.44. The strength was driven by weather, economic improvement over the prior year period, timing differences around O&M, which should reverse in the balance of the year, and a favorable tax item.

Given the strong quarter, we are raising our 2010 estimate from $2.35 to $2.40 per share. Citing uncertainty around the sustainability of the positive economic signs seen so far this year, SO left 2010 guidance unchanged at a range of $2.30-$2.36 per share. We are also introducing a 2011 estimate of $2.50 per share. Primary 2011 drivers are more normal weather offset by the benefit of new rates in Georgia, which will take effect at the beginning of the year.

SO indicated it has started to see positive economic signs, including:

- Usage by the primary metals sector up 36%, primarily to serve the auto sector.
- Transportation up 13.6%, primarily automotive, with the Georgia KIA plant coming online.
- Chemical sector up 9.5%.
- Housing permits up 4.5%, which should lead new connections for electric service.
- Weather-normalized Residential sales up 1.6%.

1Q REVIEW

Driving SO's improved operating earnings was a 10.3% increase in retail sales (Residential +20.6%, Commercial +3.4% and Industrial +6.7%). Major factors reconciling the $0.18 per share earnings increase are: higher weather-adjusted retail sales (+$0.03); rate impacts (+$0.04); weather (+$0.10); wholesale sales and transmission revenues (+$0.03); higher O&M (-$0.03), lower depreciation and amortization (+$0.04); a tax credit (+$0.02); lower results at Southern Power related to contract expirations (-$0.02) and a higher share count (-$0.03). Shares outstanding were 823 million vs. 780 million. Trailing 12-month earnings stand at $2.50 per share.

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	$0.42	-10.6%	$0.60A	42.9%	--	--
2Q	$0.61	-3.2%	$0.58	-4.9%	--	--
3Q	$0.99	-2.0%	--	--	--	--
4Q	$0.31	19.2%	--	--	--	--
YEAR	$2.32	-2.1%	$2.40	3.4%	$2.50	4.2%

Source: KeyBanc Capital Markets Inc. estimates

CMS ENERGY CORPORATION (CMS-NYSE) — SOLID QUARTER; RAISING PRICE TARGET —

reprinted from 04/26/2010

Rating	BUY
Price	$16.38
12-Mo. Price Target	$18.00
Dividend	$0.60
Yield	3.7%
52-Wk. Range	$11-$16
Trading Volume	2,954
Market Cap. (mm)	$3,980.3
Shares Out. (mm)	243.00
Book Value/Share	$11.42

Fiscal Year End	December
2011E	$1.45
2010E	$1.35
2009A	$1.26
2011 P/E	11.3x
2010 P/E	12.1x
First Call 2011E	$1.47
First Call 2010E	$1.35

Next Quarter	June
Estimate	$0.28
Vs.	$0.26
First Call Estimate	$0.28

ACTION STATEMENT.

CMS Energy Corporation (CMS-NYSE) reported a strong quarter, despite weather that was somewhat more mild than normal. Additionally, management indicated that the Michigan economy was improving more quickly than it had forecast, which bodes well for electric sales to industrial customers. We are raising our price target to $18 (from $16.50) and are introducing a 2011 estimate of $1.45 per share.

KEY INVESTMENT POINTS

CMS reported ongoing 1Q10 results of $0.38 vs. $0.30 per share. This is ahead of our $0.37 estimate and consensus of $0.36.

We think results were particularly strong since the quarter included expensing $0.03 of disallowed power supply costs in prior years.

Management indicated that it now forecasts growth in electric sales over 2009, vs. a prior view for a volume decline. The improved outlook is driven by higher forecasted industrial sales.

We are introducing a 2011 estimate of $1.45 per share. We are also revising our price target to $18 from $16.50 per share. We maintain our **BUY** rating on shares of CMS.

VALUATION

Our $18 price target is derived from applying the 2011 group average P/E of 12.2x to our 2011 estimate of $1.45 per share. We consider this valuation conservative given that CMS currently enjoys approximately $800 million of net operating loss carry-forwards and AMT credits (at December 31, 2009). Shares currently trade at 11.3x our 2011 estimate. Our price target represent a P/E multiple of 12.4x.

RISKS

We believe the primary risk that could impede CMS from achieving our price target would be a change in the regulatory treatment the Company has received as CMS has worked to repair its balance sheet and refocus on its regulated Michigan operations. Additionally, if the economy were to weaken again, Michigan could fare more poorly than the rest of the country.

1Q10 REVIEW

CMS reported 1Q10 results of $0.34 vs. $0.30 per share. Excluding 1Q10 severance charges of $0.03 and a $0.01 loss at discontinued operations, results were $0.38 vs. $0.30. Positive drivers include new electric rates and electric decoupling, self implemented gas rates and improvements at Enterprises, driven by mark-to-market. Partly offsetting these were milder weather, a charge for disallowed power supply costs and more electric customers switching to competitive suppliers. The 10% cap on switching has been reached.

Management indicated that since its early March investor meeting, economic conditions in Michigan appear to have improved, particularly the outlook for industrial power demand. As such, management is now looking for a 2% increase in overall electric demand vs. a prior view of a 1% decline. On a weather adjusted basis, residential, commercial and industrial demand growth is now forecasted to be: -1%, flat to +0.5% and 8%, respectively. The prior respective view was: -1%, -2% and -0.5%.

We have introduced a 2011 estimate of $1.45 per share. Given multiple expansions within the group, we have raised our price target from $16.50 to $18 per share.

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	$0.30	-31.8%	$0.38A	26.7%	--	--
2Q	$0.26	44.4%	$0.28	7.7%	--	--
3Q	$0.32	-3.0%	--	--	--	--
4Q	$0.38	26.7%	--	--	--	--
YEAR	$1.26	0.8%	$1.35	7.1%	$1.45	7.4%

Source: KeyBanc Capital Markets Inc. estimates

PINNACLE WEST CAPITAL CORPORATION (PNW-NYSE) — MANAGEMENT AND ARIZONA REGULATION; KEY TAKEAWAYS FROM INVESTOR MEETINGS — *reprinted from 04/20/2010*

Rating	HOLD
Price	$37.49
12-Mo. Price Target	NA
Dividend	$2.10
Yield	5.6%
52-Wk. Range	$25-$39
Trading Volume	1,128
Market Cap. (mm)	$3,798.5
Shares Out. (mm)	101.32
Book Value/Share	$32.95

Fiscal Year End	December
2011E	$3.05
2010E	$3.00
2009A	$2.33
2011 P/E	12.3x
2010 P/E	12.5x
First Call 2011E	$3.02
First Call 2010E	$2.99

Next Quarter	March
Estimate	$0.00
Vs.	($0.25)
First Call Estimate	($0.05)

ACTION STATEMENT

We recently met with key executives of Pinnacle West Capital Corporation (PNW-NYSE) and separately with regulators from the Arizona Corporation Commission (ACC) and the director of the Residential Utility Consumers Office (RUCO). Overall, we still believe the 2009 rate case settlement was a constructive step in Arizona regulation and that PNW is determined to meet its plan commitments as outlined in its rate case settlement. In return, we remain watchful for regulators and settling parties to continue their constructive support in the Company's next rate case filing in June 2011. We are vigilant as to the outcome of state elections in November and its influence on Arizona regulatory leadership and direction. Shares of PNW trade at 12.5x our 2010E of $3.00 per share compared to the peer group average P/E multiple of 12.6x. We view shares as essentially fairly valued supported by an above-average 5.6% yield and maintain our **HOLD** rating.

KEY INVESTMENT POINTS

We believe that ACC Chairman Mayes (Republican), who is term-limited at the end of this year, is trying to leave behind a utility regulatory rule-making framework in Arizona that brings together affected parties through workshops, explores mechanisms that provide rate-making stability, and offers more clarity on utility investment recovery and returns on investment.

After meeting with ACC Commissioner Kennedy (Democrat) and Commissioner Newman's (Democrat) policy advisor, we believe that their top priorities are to make Arizona a leader in solar generation and technology, although it remains to be seen whether they will support these investments at an appropriate return to investors.

We were surprised with RUCO director Jodi Jerich's (Republican) constructive approach to rate-making and believe she understands and progressively agrees with the concept that a utility with strong credit metrics ultimately helps mitigate rate increases for ratepayers.

We believe that the outcome of the November state elections are important to the future regulatory climate in Arizona as the RUCO director was appointed by the Republican Governor and that two Commissioner seats (both Republican) are up for election. We believe that Democratic wins may give investors pause and the need to reassess the new officials in office and the future regulatory direction in the state.

Finally, we believe that PNW management is committed to fulfilling its obligations under its Arizona Public Service (APS) regulated utility subsidiary settlement as evidenced by the recent successful equity offering and planned investments in solar generation. In return, we would keep a watchful eye on regulators and settling parties for their continued constructive support in the Company's next rate case filing in June 2011.

VALUATION

Based upon our 2010 earnings estimate of $3.00 per share, PNW shares trade at P/E of 12.5x compared to the utility peer group average P/E of 12.6x, which we view as being essentially fairly valued. Shares are supported by an above average 5.6% yield and favorable long-term demographic customer growth in Arizona, offset by a slow economic outlook for 2011 and the need for timely regulatory support in the Company's next rate case filing likely to be in June 2011.

RISKS

We believe the primary risks for PNW shares are a prolonged economic downturn hurting sales revenues or a faster than projected return to growth in Arizona creating additional costs and regulatory lag, both of which could potentially lead to deterioration in APS's credit metrics (currently one notch above sub-investment grade), the timing and amount of future equity issuances tentatively planned for sometime post-2012, unexpected operating risk (plant outages) cutting into margins especially during periods of base rate stability as outlined in the settlement, and a regression by regulators back to historically restrictive regulation in Arizona that precludes the Company from earning its authorized returns and timely recovery of its actual costs of service.

DISCUSSION

We recently met with key executives of PNW and separately with regulators from the Arizona Corporation Commission (ACC) and the director of the Residential Utility Consumers Office (RUCO). Key takeaways from our investor meetings are discussed below:

ARIZONA REGULATORY UPDATE

Arizona Corporation Commission (ACC)

Separately, we met with ACC Chairman Kristin Mayes, Commissioner Sandra Kennedy, and Commissioner Paul Newman's policy advisor.

Chairmen Kristin Mayes

We believe that Chairman Mayes (Republican), who is term-limited at the end of this year, is trying to leave behind a utility regulatory rule-making framework in Arizona that brings together affected parties through workshops, explores mechanisms that provide rate-making stability, and offers more clarity on utility investment recovery and returns on investment. Her focus over the next eight months is to gain solid traction on renewable generation development and Renewable Energy Standard (RES) compliance in the state, get rule-making for energy efficiency in place, and make steady progress on decoupling. She would like to see some progress in the development of the 280 MW Solana concentrating solar plant [APS has contracted for all the output with a 30-year purchase power agreement], but would be amenable to APS proposing other renewable rate-based opportunities as backfill if the project fails due to third-party developer financing. Ideally, Chairman Mayes would like see a stricter 25% by 2025 renewable portfolio standard (up from the current 15% by 2025) and for the Commission to treat all renewables as mainline resources not segregated out for special tariff treatment, although we view these proposed changes to the RES as unlikely to be adopted in the near term. Generally, Chairman Mayes supports the idea of smaller rate tariffs that pair well with incremental investment. The Chairman believes that the state is best served by a mix of independent power producer (IPP) developed projects and utility-owned projects, particularly given the fact that contracts to purchase power from IPPs are a credit negative since they are imputed as debt by credit rating agencies.

Chairman Mayes is optimistic that Commission Staff remains committed to a shorter 12-month general rate case adjudication process as outlined in the APS settlement, but feels any more state/staff budgetary cuts at the Commission could endanger that effort.

Commissioner Sandra Kennedy

Commissioner Kennedy (Democrat) was elected to the ACC in November 2008 as part of a "solar team" of candidates, whose top priority was to bring renewable solar energy to Arizona. She is a firm believer in the cause of moving Arizona toward more renewable generation and is in favor of raising the renewable energy standard. She is also supportive of low-income, minorities, and elderly consumers participating in distributed renewable energy opportunities and does not yet have a view on electric revenue decoupling. Commissioner Kennedy believes that a healthy utility can act as a driver of state growth in green technology jobs. She also thought that the 12-month general rate case adjudication process as outlined in the APS settlement may be difficult to achieve.

Commissioner Paul Newman (Policy Advisor Nancy LaPlaca)

Commissioner Newman (Democrat) was also elected to the ACC in November 2008 as part of the "solar team" of candidates. According to his policy advisor, he believes that an all-out effort toward solar/renewable technologies should be of the utmost priority, particularly given Arizona's solar resources and the state's weak position in solar so far. We believe Commissioner Newman's policy priority appears to be disconnected from fully engaging and attracting investors as: 1) investors will allocate capital to the best returns and not the best resource; and 2) if there is a desire for utilities to become innovators in renewable technologies, the regulators appear to ignore the fact that the current system does not offer returns commensurate with the risk inherent in developing and implementing new technologies.

Residential Utility Consumers Office (RUCO)

As the ratepayers' advocate in utility rate proceedings, RUCO in Arizona is led by Director Jodi Jerich. Ms. Jerich was appointed to lead RUCO by Republican Governor Jan Brewer when state leadership changed over in January 2009 after former Democratic Governor Janet Napolitano left to work for President Obama's administration. Generally speaking, we were surprised with Director Jerich's constructive approach to rate-making and believe she understands and progressively agrees with the concept that a utility with strong credit metrics ultimately helps mitigate rate increases for ratepayers.

Director Jerich took over settlement negotiations from her predecessor last year in APS's general rate case and believed it was important for the ratepayers' advocate to be open to the idea of a settlement and have its voice heard. RUCO's former position prior to the settlement had been for zero rate increases. Perhaps signaling a policy shift in this office, Director Jerich explained that her goal in supporting the APS settlement was an attempt to go from "patient triage to rehabilitation", or in other words, to get APS out of the cycle of constant and emergency rate case filings and threat of credit rating downgrades to a period of rate stability for ratepayers (rate-freezes) and improving credit metrics and lowering expenses at the Company.

Director Jerich is supportive of the concept of decoupling, but in favor of a more tiered-incentive approach whereby utilities are incentivized based on increasing ratepayer conservation. She also supports expedient rate case cycles and the concept of using a forward test year in rate case filings, where using six months of actual utility results could then be projected and trued-up six months later. The accounting issue of treating transmission line extension fees as revenues will be reevaluated during APS's next rate case and RUCO's position on the issue may depend on the state of the economy. Director Jerich feels that a stronger economy would allow developers to absorb the costs while in a weaker economy with existing empty homes, rates can be kept lower if there is no socialization of outlier builder costs to extend transmission lines. While not a strong solar advocate given costs, she seems to accept the fact that "the solar train has left the station" in Arizona. RUCO's priority appears to be maximizing the benefit for given investment dollar and getting the most efficient use for the money charged to ratepayers ("biggest bang for the buck") for solar technology development in the state.

STATE ELECTION COULD HAVE CONSEQUENCES

We believe that the outcome of the November state elections are important to the future regulatory climate in Arizona as the RUCO director is appointed by the Governor and that two Commissioner seats (both Republican) are up for election. As both the ACC and RUCO are currently under Republican leadership, we believe that Democratic wins may give investors pause and the need to reassess the new officials in office and the future regulatory direction in the state.

A Democratic win in the gubernatorial election would change who is appointed to become the next RUCO office director. Thus, we are uncertain as to whether current RUCO Director Jerich and her constructive take on rate-making will play a role in APS's next general rate case proceedings from June 2011 to mid-2012. We do believe, however, that Ms. Jerich would likely retain her position at RUCO if incumbent Governor Brewer is elected.

At the ACC, the chairmanship is up for grabs. Republican Commissioner Gary Pierce, who would have the most seniority, could potentially become Chairman if he were to win re-election and there remained a Republican majority to replace the seat of the term-limited Republican Chairman Mayes. However, if Democrats gained a majority on the ACC, we are unsure as to who the five Commissioners at that time would elect as Chairman, as it could depend on seniority or party affiliation or any number of political factors. While we are not so much concerned as to who is titled the next Chairman, we do believe there could be a leadership vacuum at the ACC with the departure of Chairman Mayes who is well-versed in utility regulation and offered a strong sense of direction and stability that investors sought in Arizona moving toward more constructive rate-making. We do believe that PNW will do its utmost to educate Commissioners and to preserve constructive regulatory relationships, no matter what the outcome of the election.

PNW EQUITY RAISE TO FINANCE CAPITAL INVESTMENT SHOWS COMMITMENT TO THE SETTLEMENT TERMS

On April 14, 2010, PNW successfully issued 6.9 million shares at $38 per share ($253 million net proceeds). The proceeds will be used in turn to fund capital expenditures (repaying approximately $160 million in short-term debt that was used to fund capital expenditures) and for general corporate purposes. We believe the offering amount was somewhat smaller than what the Street was looking for (we had estimated around $300 million), but PNW will also receive $80 million in tax benefits this year with the wind-down of Suncor real estate subsidiary. Management indicated that it would pursue additional means to inject equity into the utility without necessarily having to issue equity. Under the terms of the settlement, management committed to a $700 million infusion of equity into its APS utility subsidiary by the end of 2014.

PNW is in the midst of a large capital program, spending close to $1 billion per year, mostly related to the Arizona wanting to become a leader in renewable (particularly solar) generation, as well as having to maintain a large transmission and distribution system in its service territory. The capital expenditure forecasts for the next three years are $954 million, $1.009 billion and $1.167 billion in 2010, 2011 and 2012, respectively, and the utility forecasts 6% compounded annual growth in rate base through 2012 over a 2007 base. Major renewable projects to be owned by the utility and rate-based and allowed to earn a return on include:

AZ Sun Program: $500 million investment to own 100 MW of photovoltaic solar plants to be placed into service 2011 through 2014. The first 50 MW are allowed recovery and return on investment through the RES adjustor mechanism, which translates into approximately $0.06 of earnings per share for every 25 MW installed.

Two request for proposals (RFP): 15-50 MW of photovoltaic solar projects and 15-100 MW of Arizona wind projects.

Also agreed to in the general rate case settlement was for the Company to achieve 1.7 million MWh of additional renewable energy resource generation or savings to be in service by the end of 2015, essentially doubling the near-term RES requirements of 5% retail sales from renewable energy by 2015 (long-term RES is 15% by 2025). We believe the planned investments in solar generation demonstrate a good faith effort by PNW to meet its renewable commitments. In return, we would keep a watchful eye on regulators and settling parties for their continued constructive support in the Company's next rate case filing in June 2011, particularly related to PNW's cooperation in achieving a 12-month time line to resolve in the case.

Future other projects at the Company include $520 million of new transmission investments for over 270 miles of new lines (recoverable through FERC formula rates at 10.75% allowed ROE and ACC-approved retail transmission cost adjustor "TCA" mechanism) and identifying renewable-related transmission projects.

EPS (Net) Summary

	2009A	% CHG	2010E	% CHG	2011E	% CHG
1Q	($0.25)	NM	$0.00	NM	--	--
2Q	$0.77	-25.2%	--	--	--	--
3Q	$1.96	27.3%	--	--	--	--
4Q	($0.16)	NM	--	--	--	--
YEAR	$2.33	-3.7%	$3.00	28.8%	$3.05	1.7%

Source: KeyBanc Capital Markets Inc. estimates
Note 9: 2009 Q1: includes $0.03 MTM loss and excludes $1.30 net losses at SunCor real estate segment
Note 10: 2009 Q2: includes $0.03 MTM gain and excludes $0.09 of net losses at SunCor real estate segment
Note 11: 2009 Q3: includes $0.05 MTM gain and excludes $0.12 of net losses at SunCor real estate segment
Note 12: 2009 Q4: includes $0.05 MTM gain and excludes $0.14 of net losses at SunCor real estate segment
Note 13: 2010 Annual: On 4/14/2010, PNW issued 6.9 million shares at $38 per share.

CLECO CORPORATION (CNL-NYSE) — KEY TAKEAWAYS FROM CNL AND LOUISIANA COMMISSION INVESTOR MEETINGS— *reprinted from 04/07/2010*

Rating	HOLD
Price	$27.56
12-Mo. Price Target	NA
Dividend	$0.90
Yield	3.3%
52-Wk. Range	$20-$28
Trading Volume	320
Market Cap. (mm)	$1,664.3
Shares Out. (mm)	60.39
Book Value/Share	$18.52

Fiscal Year End	December
2010E	$2.10
2009A	$1.73
2008A	$1.70
2010 P/E	13.1x
2009 P/E	15.9x
First Call 2010E	$2.08
First Call 2009A	$1.73

Next Quarter	March
Estimate	$0.35
Vs.	$0.18
First Call Estimate	$0.30

ACTION STATEMENT

We recently met with executives of Cleco Corporation (CNL-NYSE) and separately with regulators from the Louisiana Public Service Commission (LPSC). Overall, we remain comfortable with CNL's favorable regulatory treatment in Louisiana and believe that management has consistently demonstrated a proven ability to deliver on its business plan. Shares of CNL trade at 13.1x our revised 2010E of $2.10 per share, compared to the peer group average P/E multiple of 12.8x. We view the modest premium valuation as appropriate and maintain our **HOLD** rating on the shares.

KEY INVESTMENT POINTS

With the February 12, 2010, start of commercial operation for the 600 MW solid fuel (primarily pet coke) Rodemacher Unit 3 generation plant (at a cost of approximately $1 billion), we believe CNL management has demonstrated a proven ability to deliver on its business plans.

Near term, CNL is busy optimizing its portfolio by ramping up Rodemacher Unit 3 output in time to help serve summer peak season loads, working to complete the sale of one 580 MW combined cycle gas-fired Acadia Power Station unit to Entergy Louisiana before the end of the year, building out the Acadiana load pocket transmission project through spring 2012, starting site construction for the 33 MW gas turbine Teche Blackstart project and managing costs and operations.

We believe longer-dated opportunities for CNL exist around growing retail load as third-party contracts with electric cooperatives in the region expire by the end of 1Q14, executing the Evangeline merchant plant value-extraction strategy, deploying advanced metering infrastructure, assessing the impact of environmental mandates, exploring other utility-related projects and potentially restructuring the balance sheet.

We believe CNL may detail a more formal long-term business plan later this summer after a strategy meeting with the Company's Board of Directors. We also believe that CNL will steadily grow the dividend payout ratio toward the middle of its target range of 50-60% (payout is currently at 48% of the mid-point of 2010 guidance of $2.05-$2.15 per share).

Also, after meeting with LPSC Commissioner Clyde Holloway and LPSC Executive Secretary (CEO) Eve Gonzalez, we remain comfortable with CNL's supportive regulatory treatment in Louisiana, in part due to the Company's forthcoming and proactive efforts with the LPSC generally fostering a constructive regulatory environment.

We are raising our 2010 earnings estimate to $2.10 from $2.05 per share for favorable weather in 1Q10, cost control focus and modest interest savings from the acceleration of refunding AFUDC funds to ratepayers.

VALUATION

Based upon our 2010 estimate, shares of CNL trade at 13.1x, compared to the peer group average P/E multiple of 12.8x. Given the potential upsides around the future of the Evangeline asset, we believe this is reasonable. We therefore maintain our **HOLD** rating on the shares.

RISKS

We believe the primary risks to CNL shares are a prolonged economic weakness in the Southeast, which would act to produce prolonged weakness in demand in the region, fuel audit recovery of revenues from prior years and not completing the sale of the Acadia merchant asset to Entergy (requires LPSC approval).

DISCUSSION

We recently met with key executives for Cleco Corporation and separately with LPSC Commissioner Clyde Holloway and LPSC Executive Secretary Eve Gonzalez. Key takeaways from our meetings are discussed below:

Rodemacher Unit 3 Powers Up the Regulated Utility Portfolio

With the February 12, 2010, start of commercial operation for the 600 MW solid fuel (primarily pet coke) Rodemacher Unit 3 generation plant, CNL is now busy ramping up Rodemacher Unit 3 output in time to help serve summer peak season loads and to reach plant capacity goals by the end of the year. During testing, Rodemacher operated at a heat rate under 9,000 btu/kWh, better than the manufacturer's commitment of 9,200 btu/kWh. We believe that successfully constructing, integrating and optimizing the new $1 billion plant (approximate capital cost) into Cleco Power's (the regulated utility) generation portfolio demonstrates management's ability to deliver on its stated business plan ever since construction began in May 2006; planning started before then.

As power supplied from Rodemacher Unit 3 ramps up to serve its utility customers, purchased power or generation from older self-owned stations can be displaced or allocated more efficiently. In 2009, roughly 53.6% (5,712 GWh) of Cleco Power's energy needs were met with purchased power. The completed February 23, 2010, acquisition of 50% of Acadia Power Station (one 580 MW gas-fired unit) by Cleco Power is also expected to help reduce purchased power volumes in the future. Fuel and purchased power costs are recoverable through a monthly adjustment clause, subject to refund, approval and periodic (biennial) fuel audit by LPSC.

NEAR-TERM BUSINESS COMMITMENTS

- 50% of Acadia Power Station sale - CNL continues to work on completing the sale of the other 50% of Acadia Power Station (one 580 MW gas-fired unit) to Entergy Louisiana before the end of the year.
- "Acadiana Load Pocket" joint transmission project - Work is underway to upgrade the transmission system and improve reliability in south central Louisiana. Current goals are to have the project completed before summer of 2012, with some portions energized and online in 2011. The total cost for the project is approximately $250 million, with Cleco Power's portion of the costs around $150 million (including AFUDC). The Company's 2010 construction costs for the project are estimated to be about $55 million, excluding AFUDC. CNL's recent formula rate plan allows for the recovery of future revenue requirements related to the project. CNL may be able to adjust 2011 rates for a portion of the capital spent.
- Teche Blackstart Project - Approved in December 2009, the siting of a gas-peaking turbine at Teche Power Station will allow Cleco Power to return its generating system to service more efficiently than is currently possible in the event of a total system shutdown (blackstart process). A refurbished 33-MW gas turbine, to be designated Teche Unit 4, was procured as phase 1 of the project. Phase 2 site construction began in March 2010 and the project is expected to be completed in 2Q11 at a $31 million total estimated cost. Under its settlement agreement, rates may be adjusted for Teche if CNL is under-earning its authorized return. Teche will be included in the test to determine if CNL is over-earning.
- Managing costs and operations - Management seemed confident in its ability to keep costs in line with the test year it had forecast in its rate base. The Company also expects to contribute $70 million cash into the pension over the next five years, with these contributions likely to be more back-end loaded.

LONG-TERM STRATEGIC EFFORTS

We anticipate CNL will detail a more formal long-term business plan later this summer after a strategy meeting with the Company's Board of Directors. We highlight below our view of longer-term opportunities at CNL:

- **Dividend and capital return** - We believe that CNL will steadily grow the dividend payout ratio toward the middle of its target range of 50-60% (payout is currently at 48% of the mid-point of 2010 guidance of $2.05-$2.15 per share), as opposed to rapidly achieving that outcome. The potential also exists to review balance sheet capacity in light of positive free cash flow projections in the longer term, with the potential to utilize more leverage if an attractive opportunity was found. We believe CNL management will be conservative with utility capital investments in the future, maintaining a low utility risk profile.
- **Retail load growth** - There are three third-party (NRG Power Marketing) contracts with electric cooperatives in the region that expire by the end of 1Q14, totaling about 900 MW capacity. As the contracts expire, this will provide an opportunity for CNL to bid to supply electricity to the co-op or to explore serving the territory outright. Bidding could take place in late 2012 or early 2013. The Company feels good about its prospects in being able to win these contracts, particularly as the 1,743 MW Big Cajun II coal-fired power plant owned by NRG will likely need to install environmental scrubbers by 2015 (CNL estimates capital requirements at roughly $600/kw to scrub that plant). We believe if CNL were to win this load, the commission may look favorably on ratebasing Evangeline.
- **Environmental Compliance** - CNL management continually assesses possible federal and state environmental emissions rules and mandates that may need to be met (mercury, SO2, NOx, carbon, etc.), not only for investments that may need to be made in its own portfolio, but for potential business opportunities it may present in its region. CNL estimates $3.0 million in environmental capex for 2010, down from $4.9 million spent in 2009. While there is considerable uncertainty around future environmental regulations, CNL believes under fairly strict regulations, it might be required to spend in the hundreds of millions to be in compliance.

- **Evangeline Power Station** - All 775 MW of Evangeline nameplate capacity is currently dedicated to J.P. Morgan Ventures Energy Corporation (JPMVEC). CNL entered into a new market-based tolling agreement with JPMVEC effective March 1, 2010 through December 31, 2011, with a one-year extension option for JPMVEC. In the meantime, CNL can strategically plan on how best to extract value from the Evangeline plant asset. Given the scarcity of combined-cycle gas fired plants in Louisiana, potential environmental mandates that will have to be met by other coal plant owners in the region and possible pickup in the economy in the future, CNL feels that Evangeline remains a valuable asset in the long term post-2011 (or post-2012 option) that can be run competitively.
- **Advanced Metering Infrastructure (AMI)** - In October 2009, CNL was awarded a $20 million economic stimulus grant from the U.S. Department of Energy to deploy AMI smart-grid technology. The Company estimates the project cost at $73 million and would be completed in 2012. CNL is still evaluating the project, how it plans to fund the remaining $53 million and whether or not to accept the grant with DOE requirements.

LOUISIANA PUBLIC SERVICE COMMISSION (LPSC) AND REGULATORY TAKEAWAYS

A $3.2 billion fuel audit for CNL is underway at the LPSC for 2003-2008 (backlogged from the normal biennial process). It is our sense that the reason for the aggregated fuel audit is the LPSC's attempt to catch up in the fuel audit process for all utilities in Louisiana, as required by the fuel adjustment clause. There are no indications as of yet as to any material adverse effects requiring refund of previously recorded revenues, although this does remain a risk and issue to watch for CNL at the Commission.

LPSC Commissioner Clyde Holloway believes that Louisiana is likely to have a renewable portfolio standard (RPS), potentially 12.5% by 2020, and possibly on a voluntary basis. Biomass is the primary renewable resource in the state, although energy efficiency measures may also count toward meeting RPS requirements. Commissioner Holloway represents 60-65% of CNL's service territory and considered himself the "most pessimistic" on the Commission as to ROEs, but is supportive of CNL's rate plan (10.7% authorized) and is understanding of the need for investor returns to attract capital investment. We believe he has a generally good understanding of the issues and view his comments favorably with respect to CNL regulatory support. He also believes that the electric cooperatives in the region need to be prepared for their upcoming power supply contract expirations and should manage the process accordingly. His priorities on the LPSC include improving transmission in the region, getting better operational data on the use of renewable resources, reviewing the solar subsidy in the state and exploring better hedging policies to address pricing volatility.

LPSC Executive Secretary Eve Gonzalez is the Chief Executive Officer of the Commission, appointed by the five Commissioners and responsible for the day-to-day operations at the Commission. She cited the renewable portfolio standard, economic development, formula rate plan design, transmission reliability and environmental investment recovery as important issues at the LPSC, and also felt that CNL is very constructive in working with the regulators.

After meeting with Commissioner Holloway and Executive Secretary Gonzalez, we remain comfortable with CNL's supportive regulatory treatment in Louisiana, in part due to the Company's forthcoming and proactive efforts with the LPSC generally fostering a constructive regulatory environment.

As an example of this constructive relationship, CNL and the LPSC collaborated to address markedly higher bills resulting from new rates and extremely cold February weather. CNL agreed to accelerate the refund of funds it collected during Rodemacher construction. This offered ratepayers immediate relief and will lower the total refund amount from $182 million to $168 million, given that the balance is accruing interest at 11%.

EPS (Net) Summary

	2008A	% CHG	2009A	% CHG	2010E	% CHG
1Q	$0.37	208.3%	$0.18	-51.4%	$0.35	94.4%
2Q	$0.49	96.0%	$0.47	-4.1%	--	--
3Q	$0.62	-15.1%	$0.93	50.0%	--	--
4Q	$0.22	10.0%	$0.15	-31.8%	--	--
YEAR	$1.70	29.8%	$1.73	1.8%	$2.10	21.4%

Source: KeyBanc Capital Markets Inc. estimates
Note 1: 2008 Annual: 2008 quarterly and annual results are GAAP reported earnings. (Excluding tax levelization and COLI adjustments, FY08 operational earnings were $1.75)
Note 2: 2009 Annual: 2009 quarterly and annual results are operational earnings which exclude tax levelization and COLI adjustments and include mark-to-market on energy hedge positions.

ENTERGY CORPORATION (ETR-NYSE) — QUICK ALERT: UNWINDS PROPOSED NUCLEAR SPIN-OFF; DIVIDEND RAISED 10.7% — *reprinted from 04/05/2010*

- This morning, Entergy Corporation (ETR-NYSE) announced plans to unwind the businesses associated with its proposed merchant nuclear spin-off (Enexus and EquaGen), effectively ending the Company's active pursuit of the spin-off transaction and redirecting the Company's efforts into other strategies.
- ETR lawyers are evaluating and working to preserve the Company's legal rights in response to the New York Public Service Commission decision to reject the spin-off transaction on March 25, 2010.
- ETR estimates a total potential write-off charge of $0.40-$0.45 per share to reflect capitalized costs incurred to date and previously identified spin-off dis-synergies related to the spin-off in 2010.
- Quarterly dividend was raised 10.7% to $0.83 from $0.75 per share.
- ETR expects to execute on a $750 million share repurchase program previously authorized in 4Q09.
- There was no mention of current 2010 earnings guidance in the press release (previously at $6.40-$7.20 per share).
- ETR provided a long-term segment financial outlook of 5-6% compound annual earnings growth from 2010-2014 (over a 2009 base year) at the regulated utility and relatively constant adjusted EBITDA at Entergy Nuclear.
- ETR indicated the potential ability to return up to $5 billion to investors over the next five years through dividends and repurchases.
- We expect a mixed reaction to the announcement. While the dividend hike is meaningful, we believe investors may have anticipated upsizing the repurchase authorization. We expect that fairly weak trading volumes in the sector lately suggest the repurchase activity could drive the share price. Any suggestion during the call of additional repurchases in the near term would be viewed favorably.

APPENDIX

Table 8. Water Supply Forecast

(% of Average)

Runoff Period (April - Sept.)	2008 Jan	2008 Feb	2008 Mar	2008 Apr	2008 May	2008 Jun	2008 July	2009 Jan	2009 Feb	2009 Mar	2009 Apr	2009 May	2009 Jun	2009 July	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May	2010 Jun	2010 July
Snowpack																					
Idaho																					
Upper Snake River Basin	87	102	102	106	118	149	NA	93	93	89	97	108	69	NA	56	63	57	56	58		
Panhandle Region Basin	99	111	113	119	129	132	NA	69	80	76	90	91	89	NA	60	58	52	55	60		
Oregon																					
Upper John Day Basin	89	115	112	119	186	NA	NA	81	73	72	97	70	NA	NA	72	80	84	76	66		
Upper Deschutes Basin	107	146	141	153	162	176	NA	128	101	94	120	120	76	NA	90	71	60	67	85		
Washington																					
Spokane River Basin	101	122	137	144	174	177	NA	81	83	83	139	97	68	NA	56	57	52	51	54		
Precipitation																					
Idaho																					
Upper Snake River Basin	121	91	125	66	114	120	25	96	70	126	130	85	61	60	75	38	61	70	NA		
Panhandle Region Basin	117	97	127	81	67	121	31	97	61	144	74	106	261	101	64	43	71	77	NA		
Oregon																					
Upper John Day Basin	147	75	82	74	140	76	8	64	61	143	98	110	150	28	102	59	79	83	NA		
Upper Deschutes Basin	147	81	99	86	96	66	20	60	67	121	77	130	119	10	81	53	77	83	NA		
Washington																					
Spokane River Basin	123	100	135	85	63	134	35	102	67	144	69	109	72	99	64	46	68	74	NA		
Reservoir Storage																					
Idaho																					
Upper Snake River Basin	65	71	79	82	87	96	96	100	104	112	105	103	114	113	115	115	120	126	NA		
Panhandle Region Basin	108	109	108	96	96	99	100	102	99	104	112	106	103	103	103	106	111	118	NA		
Oregon																					
Upper Deschutes Basin	99	98	98	99	103	110	114	114	106	102	103	105	112	111	110	107	106	105	NA		
Washington																					
Spokane River Basin	33	38	62	68	181	91	98	83	62	86	98	97	99	98	47	41	55	73	NA		
Stream Flow																					
Avista Corp. (AVA)*																					
Clark Fork River (75%) - Whitehorse Rapids	87	91	100	106	102	104	109	90	88	87	97	96	95	92	77	70	64	60	61		
Spokane River (25%)	94	104	110	128	122	122	152	88	82	81	101	97	115	108	83	57	53	52	55		
Idacorp (IDA)																					
Snake River-Brownlee Reservoir	74	86	89	88	79	75	68	73	69	61	82	81	76	86	60	56	49	51	52		

Note: NA - not available.
**AVA-owned hydroelectric generation is split approximately 75%/25% along Clark Fork/Spokane rivers.*
Sources: Northwest River Forecast Center (NRFC), National Water and Climate Center (NWCC), U.S. Dept. of Agriculture Natural Resources and Conservation Service (NRCS)
as of May 28, 2010

Using observed and estimated sample data input into statistical regression models, a water supply forecast attempts to predict a volume of streamflow that might pass a point on a river stream, typically during the spring and summer seasons. In the western United States, snowfall accumulation (or snowpack) in the mountains during winter and early spring becomes the source of much of the water run-off into riverstreams during the spring and summer snowmelt season. On certain mountain slopes in the Cascades or Rocky Mountains, however, future precipitation may be a more dominant driver of actual streamflow than snowmelt, thus making forecasting more difficult. While no prediction or model is perfect, streamflow forecasts can be important to operational river users (such as hydroelectric dam operators, fishermen or even white-water rafters) who make decisions based on projected river conditions.

As a service to our clients, we track the April through September streamflow forecast issued by the Northwest River Forecast Center for companies under coverage (Avista and IDACORP) that have large exposure to hydrological river conditions throughout the year. We believe investors may find incremental value in these forecasts as a possible variable of earnings for the year, offset by any fuel/power supply cost adjustment mechanisms each utility may have to address hydrology variability. The percent-of-average number listed in the table above is only a "probable" forecast within a forecasted range assuming unobstructed seasonal flow of water. In reality, water is stored in reservoirs as it flows down the river basin, where the force of falling water is used to generate electricity. Unknown or unpredictable weather variables, uncertainty in the regression models, and unforeseen changes are other factors to consider that could affect the accuracy of the water supply forecast.

Table 9. Domestic Generation Capacity for KBCM Utilities Coverage List

Company	Ticker	Capacity (MW)		Coal	Nuclear	Gas	Oil	Hydro	Wind	Other	Capacity Reported
				Generating Plants by Fuel Type							
Ameren Corp.	AEE	17,002	Owned:	59%	7%	26%	2%	5%	0%	0%	99%
			Used:	86%	12%	1%	0%	2%	0%	0%	
American Electric Power Co., Inc.	AEP	36,077	Owned:	69%	6%	23%	0%	1%	1%	0%	100%
			Used:	85%	8%	6%	0%	0%	1%	0%	
Avista Corp.	AVA	1,776	Owned:	13%	0%	29%	0%	55%	0%	3%	100%
			Used:	22%	0%	23%	0%	52%	0%	3%	
CMS Energy Corp.	CMS	7,685	Owned:	38%	0%	47%	0%	14%	0%	1%	100%
			Used:	80%	0%	10%	0%	7%	0%	3%	
Central Vermont Public Service Corp.	CV	112	Owned:	0%	18%	0%	35%	38%	0%	10%	100%
			Used:	0%	36%	0%	1%	52%	0%	12%	
Cleco Corp.	CNL	2,127	Owned:	23%	0%	77%	0%	0%	0%	0%	100%
			Used:	48%	0%	52%	0%	0%	0%	0%	
Consolidated Edison, Inc	ED	811	Owned:	0%	0%	46%	54%	0%	0%	0%	100%
			Used:	0%	0%	76%	24%	0%	0%	0%	
DPL Inc.	DPL	3,991	Owned:	71%	0%	27%	1%	0%	0%	0%	100%
			Used:	99%	0%	1%	0%	0%	0%	0%	
DTE Energy Co.	DTE	12,003	Owned:	59%	9%	21%	2%	8%	0%	1%	99%
			Used:	78%	18%	1%	0%	2%	0%	1%	
Dominion Resources, Inc.	D	26,427	Owned:	30%	22%	27%	13%	8%	0%	0%	100%
			Used:	45%	42%	10%	1%	2%	0%	0%	
Duke Energy Corp.	DUK	36,342	Owned:	47%	14%	27%	2%	9%	1%	0%	99%
			Used:	68%	25%	3%	0%	3%	0%	0%	
Entergy Corp.	ETR	30,097	Owned:	8%	34%	58%	0%	0%	0%	0%	99%
			Used:	13%	65%	21%	0%	0%	0%	0%	
Exelon Corp.	EXC	25,483	Owned:	6%	67%	11%	10%	6%	0%	0%	100%
			Used:	5%	91%	1%	0%	3%	0%	0%	
FPL Group, Inc.	FPL	38,024	Owned:	2%	15%	50%	15%	1%	16%	0%	99%
			Used:	4%	29%	50%	6%	1%	10%	0%	
FirstEnergy Corp.	FE	13,290	Owned:	56%	30%	7%	1%	5%	0%	0%	100%
			Used:	59%	39%	0%	0%	1%	0%	0%	
Great Plains Energy Inc.	GXP	5,959	Owned:	52%	9%	28%	9%	0%	2%	0%	99%
			Used:	79%	18%	2%	0%	0%	2%	0%	
IDACORP, Inc.	IDA	3,464	Owned:	30%	0%	12%	0%	58%	0%	0%	99%
			Used:	50%	0%	2%	0%	48%	0%	0%	
MDU Resources Group, Inc.	MDU	508	Owned:	71%	0%	25%	0%	0%	4%	0%	100%
			Used:	97%	0%	0%	0%	0%	3%	0%	
NiSource, Inc.	NI	3,463	Owned:	78%	0%	22%	0%	0%	0%	0%	100%
			Used:	99%	0%	1%	0%	0%	0%	0%	
NorthWestern Corp.	NWE	559	Owned:	77%	0%	12%	11%	0%	0%	0%	100%
			Used:	100%	0%	0%	0%	0%	0%	0%	
PPL Corp.	PPL	10,816	Owned:	39%	20%	13%	20%	8%	0%	0%	100%
			Used:	53%	33%	4%	1%	9%	0%	0%	
Pepco Holdings, Inc.	POM	4,661	Owned:	7%	0%	57%	35%	0%	0%	0%	99%
			Used:	37%	0%	59%	4%	0%	0%	1%	
Pinnacle West	PNW	6,274	Owned:	28%	18%	54%	0%	0%	0%	0%	99%
			Used:	46%	31%	23%	0%	0%	0%	0%	
Progress Energy, Inc.	PGN	22,362	Owned:	33%	18%	35%	13%	1%	0%	0%	100%
			Used:	46%	33%	17%	3%	0%	0%	0%	
Southern Company	SO	41,334	Owned:	47%	9%	34%	2%	7%	0%	0%	100%
			Used:	66%	15%	17%	0%	2%	0%	0%	
TECO Energy, Inc.	TE	4,443	Owned:	41%	0%	58%	1%	0%	0%	0%	100%
			Used:	58%	0%	42%	0%	0%	0%	0%	
Wisconsin Energy Corp.	WEC	5,759	Owned:	56%	0%	40%	0%	1%	3%	0%	100%
			Used:	89%	0%	9%	0%	1%	1%	0%	
Xcel Energy Inc.	XEL	16,497	Owned:	47%	10%	36%	1%	3%	1%	1%	99%
			Used:	66%	17%	15%	0%	1%	0%	1%	
Total Capacity & Fuel Mix Averages		**377,346**	**Owned:**	**39%**	**11%**	**32%**	**8%**	**8%**	**1%**	**1%**	
			Used:	**56%**	**18%**	**16%**	**1%**	**7%**	**1%**	**1%**	

Owned % = Operating Capacity (MW)

Used % = Net Generation (MWh)

Note: Data as of 2008 based on current ownership.

Source: SNL Power; Company data, KeyBanc Capital Markets Inc.

Table 10. Nuclear Outage Days by Company

Company	Ticker	1Q09 Units	1Q09 Total	1Q10 Units	1Q10 Total	Difference Units	Difference Total
Ameren Corp.	AEE	1	12.2	1	0.0		(12.2)
American Electric Power Co., Inc.	AEP	2	97.6	2	30.0		(67.6)
DTE Energy Company	DTE	1	5.4	1	7.5		2.1
Dominion Resources, Inc.	D	7	24.3	7	19.6		(4.7)
Duke Energy Corp.	DUK	7	26.0	7	27.4		1.4
Entergy Corp.	ETR	11	53.6	11	48.1		(5.5)
Exelon Corp.	EXC	17	76.5	17	122.1		45.7
FPL Group, Inc.	FPL	8	55.0	8	39.2		(15.7)
FirstEnergy Corp.	FE	4	37.9	4	33.8		(4.1)
Great Plains Energy, Inc.	GXP	1	0.2	1	7.5		7.3
PPL Corp.	PPL	2	7.2	2	41.8		34.6
Pinnacle West Capital Corp.	PNW	3	2.9	3	15.4		12.5
Progress Energy, Inc.	PGN	5	38.5	5	133.5		95.0
Southern Company	SO	6	62.0	6	72.8		10.8
Xcel Energy Inc.	XEL	3	21.7	3	0.1		(21.6)
Other Companies Not Covered	--	26	212.2	26	250.7		38.4
Total		**104**	**733.1**	**104**	**849.5**	**0**	**116.4**

Source: U.S. Nuclear Regulatory Commission (as of March 31, 2010), KeyBanc Capital Markets Inc. estimates.

Table 11. Cost Recovery Mechanisms

	AMI / Smart Grid	Bad Debt / Uncollectibles	Distribution / Delivery Service Improvement / Reliability	DSM / Energy Efficiency / Conservation	Environmental	Fuel & Purchased Power	Pension / OPEB	Revenue Decoupling	Storm Damage	Stranded Costs	Transmission / RTO	CWIP in Rate Base Before Plant In-Service	New Construction
AEE		P[1]	X[1, 2]	X	X[1]	X	X[1]						
AEP	X[1]		X[1, 3]	X[1]	X[1]	X					X[1, 4]	X[1]	G[1]
AVA						X		X[1]				X[1]	
CMS	X	P				X		P		P			
CNL						X			X				
ED					X	X	X	X			X[5]		
DPL	F		P	X	X	X			X		X[4]		
DTE		P		P	X	X		P	X	P	X[6]		
D	P[1]	X[1]	P[1]	X	X	X					X[4]		
DUK	X[1]	X[1]	X[1]	X[1]	X	X	X[1]		X[1]		X[6]	X[1]	G, I, N
ETR				X[1]		X			X[1]				N
EXC	X	P[1]		X[1]	X[1]	X				X	X[1]	X[1]	
FPL				X	X	X			X			X[7]	N, W, S
FE		X[1]	X[1, 3]	X[1]		X[1]			X[1]	X[1]	X[1, 6]		
GXP				P[1]		X[1]					X[1]		
IDA	X[1]			X		X	P	P[1]					G
MDU						X		X[1]					
NI		X[1]		X[1]	X[1]	X	X[1]	F, X[1]					
NWE						X	X[1]						
PPL	P	X		P		X				X	X	X[8]	
POM	X[1]	F, X[1]	X[1]	X[1]	X[1]	X	F	F, X[1]		X[1]	X	X[8]	S
PNW				X	X	X					X		G[9]
PGN	X[13]			X	X[1]	X			P[1]		X[1]	X[1]	N
SO				X[1]	X	X			X			X[1]	N, G[10]
TE				X	X	X			X				
WEC					X	X					X[6, 11]		
XEL				X[1]	X	X[1]		X[1]			X[6, 12]	X[1]	W

Legend
F – filed by company for cost recovery treatment, regulatory acceptance and approval to be determined
P – plan, pilot, program or law approves cost recovery, but requires a separate plan filing or prudency review with regulators (usually outside of a general rate case)
X – active cost recovery mechanism, rate adjustment clause, rider, tracker, or specific rate provision
G, I, N, S, W – (G)eneral plant/pre-construction, (I)GCC, (N)uclear, (S)olar, (W)ind

Notes
1 Not in all jurisdictions
2 80% of costs recovered as fixed nonvolumetric monthly charge
3 Only recovers vegetation management costs
4 Recovers PJM-related costs
5 Recovers purchased power payments to NYISO
6 Recovers MISO-related costs
7 Florida allows small projects less than 0.5% of a utility's plant in service as component of rate base
8 FERC-granted transmission line projects
9 Line extension fees
10 Alabama new generating facilities and Mississippi new baseload capacity
11 Defer transmission costs exceeding amounts in rates and earn WACC return on unrecovered transmission cost deferrals.
12 PSCo retail Transmission Cost Adjustment (TCA) - allows for return on CWIP for transmission investments
13 Smart Grid recovery through the Energy Conservation Cost Recovery rider in Florida, DSM/EE rider in Carolinas

Sources: compiled from Company reports and SEC regulatory filings, KeyBanc Capital Markets Inc. research

Glossary Definitions – Cost Recovery Mechanisms

AMI / Smart Grid – Costs associated with Advanced Metering Infrastructure (AMI), Smart Grid, and other related programs. A smart grid uses smart meters to directly connect customers and suppliers of electricity to observe energy usage and pricing in real time.

Bad Debt / Uncollectibles – Bad debt and uncollectible expenses, which result from the customers' inability to fulfill their obligation to pay; thus, rendering a portion of receivables unable to be collected.

Distribution / Delivery Service Improvement / Reliability – Maintaining and safely distributing power from the utility company to the customer; includes costs such as vegetation management and underground cables.

DSM / Energy Efficiency / Conservation – Costs associated with Demand-Side Management, energy conservation and efficiency efforts, including programs that manage and/or reduce energy use by customers.

Environmental – Costs associated with environmental compliance and remediation, including the reduction of emissions in accordance with current environmental laws.

Fuel & Purchased Power – Electric fuel and power supply costs, including natural gas and steam, in addition to costs for purchased power energy and capacity.

IGCC – Integrated Gasification Combined Cycle, a power plant using synthesis gas formed from coal. This gas is used to power a gas turbine whose waste heat is passed to a steam turbine system. IGCC has the potential to burn coal more cleanly.

Pension / OPEB – Cost recovery designed to minimize subsequent rate impacts from market value fluctuations of benefit plan assets tied to pension / other post-employment benefits plans.

Revenue Decoupling – By cutting the direct link between revenue and level of sales volumes (using fixed charges), decoupling is designed to eliminate the disincentive for utility companies to invest in energy efficiency or conservation programs.

Storm Damage – Costs associated with storm damages and restoration of the system.

Stranded Costs – Unrecoverable costs incurred by a utility in connection with providing services in a competitive market when customers change power suppliers, thus leaving their original utility with debts that can no longer be paid by revenue from the ratepayers for whom the plants served. Such costs may include costs for generation assets, purchased power costs, regulatory assets and liabilities, and other investments.

Transmission / RTO – Costs associated with the transmission of electricity into and across a utility service territory for retail/wholesale customers and/or the costs of providing regional transmission service through a Regional Transmission Organization.

Construction-Related:
CWIP in Rate Base (Construction-Work-In-Progress in Rate Base) – Regulatory concept under which, in limited circumstances, a regulatory body allows accelerated or early recovery into a company's rate base of accrued costs for plants under construction but not yet used and useful (in service) to serve ratepayers.

New Construction – Within the Company's footprint, these programs promote policy/project development with alternative cost recovery incentives associated with new Nuclear, Wind, IGCC, Solar, or other General plant, property, or equipment (PPE) / pre-construction costs (may use "CWIP in Rate Base" as one method of accelerated regulatory recovery).

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KeyBanc Capital Markets

			IB Serv./Past 12 Mos.	
Rating	**Count**	**Percent**	**Count**	**Percent**
BUY [BUY]	187	48.10	43	22.99
HOLD [HOLD]	195	50.10	54	27.69
SELL [UND]	7	1.80	1	14.29

ENERGY

			IB Serv./Past 12 Mos.	
Rating	**Count**	**Percent**	**Count**	**Percent**
BUY [BUY]	23	39.00	10	43.48
HOLD [HOLD]	36	61.00	22	61.11
SELL [UND]	0	0.00	0	0.00