MOODY'S INVESTORS SERVICE

Credit Opinion: Exelon Corporation

Global Credit Research - 06 Dec 2012

United States

Ratings

Category	Moody's Rating
Outlook	Negative
Issuer Rating	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
Commonwealth Edison Company	
Outlook	Stable
Issuer Rating	Baa2
First Mortgage Bonds	A3
Senior Unsecured	Baa2
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
Exelon Generation Company, LLC	
Outlook	Negative
Issuer Rating	Baa1
Senior Unsecured	Baa1
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

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Key Indicators

[1]**Exelon Corporation**

	LTM09/30/2012	2011	2010	2009
(CFO Pre-W/C + Interest) / Interest	6.2x	8.5x	7.3x	6.7x
(CFO Pre-W/C) / Debt	24.3%	43.0%	37.1%	36.0%
RCF / Debt	23.7%	34.8%	33.0%	31.4%
FCF / Debt	-1.6%	8.0%	6.5%	10.0%

[1] All ratios calculated in accordance with the Unregulated Utilities and Power Companies Rating Methodology using Moody's standard adjustments.

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

Opinion

Rating Drivers

Consolidated credit metrics declining from strong historical levels

Recent merger with financially weaker unregulated power company

System wide capital requirements plus dividends pressure free cash flow

Competitive position & consistent operations

Hedging strategies influence cash flow predictability

Corporate Profile

Exelon Corporation (Exelon; Baa2 senior unsecured, negative outlook) is the holding company for non-regulated subsidiary, Exelon Generation Company, LLC (ExGen; Baa1 senior unsecured, negative outlook) and for regulated subsidiaries: Commonwealth Edison Company (ComEd; Baa2 senior unsecured, stable), PECO Energy Company (PECO; A3 Issuer Rating, stable), and Baltimore Gas and Electric Company (BGE: Baa1; senior unsecured, stable).

On March 12th, Exelon and Constellation Energy Group, Inc. (CEG) merged. Simultaneously with merger close, Exelon legally assumed CEG's obligations, including CEG's senior unsecured and junior subordinated debt and became the obligor on CEG's existing credit facilities.

ExGen is one of the largest competitive electric generation companies in the US, as measured by owned and controlled megawatts (MW) with net capacity of 37,295 MW, including 17,115 MW of owned-nuclear capacity and 1,925 MW of nuclear capacity owned through a joint venture. In addition, the company controls another 6,125 MW of capacity through long-term contracts.

ComEd is an electric transmission and distribution (T&D) utility providing service to 3.8 million customers across northern Illinois. ComEd is regulated by the Illinois Commerce Commission (ICC) and by the Federal Energy Regulatory Commission (FERC).

PECO provides T&D service to about 1.6 million electric customers in Philadelphia as well as several surrounding Pennsylvania counties. PECO also provides gas distribution service to 490,000 natural gas customers in areas outside the city. PECO is regulated by the Pennsylvania Public Utility Commission (PAPUC) and by FERC.

BGE is a regulated electric transmission and distribution and gas distribution utility providing electricity and gas services to the city of Baltimore and ten other counties in Maryland. BGE is regulated by the Maryland Public Service Commission (MPSC) and FERC.

SUMMARY RATING RATIONALE

Exelon's Baa2 rating reflects strong historical consolidated credit metrics, due in large part to the financial performance of its unregulated generation subsidiary, and the generally predictable cash flows at its T&D subsidiaries. While the T&D subsidiaries are sizeable standalone companies, Exelon's rating remains heavily influenced by the performance of its unregulated segment, which has increased in size and importance following the CEG merger.

DETAILED RATING CONSIDERATIONS

-Consolidated credit metrics expected to decline from historical levels

Exelon's historical consolidated credit metrics have positioned the company strongly in the current category as an unregulated power holding company; however, future financial results are expected to cause those metrics to materially decline over the next several years owing to lower margins caused primarily by sustained low natural gas prices.

From 2009 through 2011, we calculate that the three year average of Exelon's cash flow (CFO pre-W/C) to debt at 39%, retained cash flow to debt at 33%, free cash flow to debt at 8.0%, and cash flow coverage of interest expense at 7.3x. By comparison, through 12 months ending 09/30/2012, we calculate cash flow to debt at 24.3%, retained cash flow to debt at 23.7%, cash flow coverage of interest expense of 6.2.x with negative free cash flow to debt of (-1.6%). These declines can be attributed to weaker commodity prices, lower amounts of bonus depreciation, a higher level of capital expenditures plus the inclusion of CEG's consolidated debt with operating results of only two quarters in this calculation. Exelon has indicated in SEC filings that bonus depreciation enhanced cash flow by $850 million during 2011 and is expected to augment 2012 cash flow by $300 million.

Prospectively, we expect financial results to weaken as margins continue to compress due to soft power prices caused in large part by sustained low natural gas prices and tepid economic demand.

-Merger with financially weaker unregulated power company

We believe that a motivating factor behind the March 2012 merger with CEG was to address the expected declining earnings trend and weaker cash flow profile beginning in 2012. As the largest unregulated power company in terms of kilowatt hours produced and retail customers served, the merger should garner the strategic benefits of linking a company that is long on generation (Exelon) with a company (CEG) that is long on customer load. As a byproduct of this linkage, the merger should considerably reduce consolidated liquidity requirements and enable the merged company to receive somewhat better margins for its electric output given the inherent stickiness of retail customer load. That being said, we note the retail electric market is highly competitive with the company continuing to be exposed to earnings and cash flow volatility due to the large unregulated business platform that now exists post merger.

We also believe that the completion of the CEG merger increases the likelihood that Exelon will remain more focused on maintaining its leadership position among unregulated power companies. To that end, we view Exelon as embracing a higher risk tolerance given the very large commodity platform that has been created with this merger. As such, we believe the company's credit metrics may need to be stronger than similarly rated peers while maintaining access to amply sized sources of liquidity.

-Near term capital requirements remain material

As a large capital intensive company, Exelon has substantial capital requirements to maintain the operation of its generation fleet while also maintaining and replacing the infrastructure of its regulated T&D utilities. Exelon is considering making up-rate investments across its nuclear fleet which, if fully completed, would add up to 1,300 MWs of additional capacity to the company's fleet at a very competitive cost. For 2012, Exelon plans to spend $6.1 billion in capital investment, including $3.8 billion at its unregulated platform, $1.275 billion at ComEd, $575 million at BGE and $425 million at PECO. In October 2012, the company announced that it would defer $1.025 billion of capital investment for extended power nuclear up-rates at LaSalle and at Limerick until 2017 and that it removed $1.25 billion of growth capital investment for new renewable projects from its capital budget. As such, 2013 capital investment at ExGen is expected to only be $2.75 billion with 2013 capital investment across the three T&D utilities approximating $2.55 billion, of which $1.4 billion was expected to occur at ComEd. The actions to defer nuclear up-rate capital investments and to remove growth capital for new renewable investments will aid future prospects for free cash flow generation, a credit positive.

-Dividend requirement may be reevaluated

Exelon has a $1.8 billion annual common dividend requirement following the merger with CEG which increased that requirement by $400 million. Given the prominence of the unregulated platform, we believe that the current dividend will be largely funded by ExGen's cash flow over the next several years, or with incremental debt given the near-term prospects for unregulated operating margins. This is particularly relevant during the next few years when BG&E is prohibited from paying a dividend (through 2014) and when regulated subsidiary ComEd's internal cash flow will be largely used to fund multi-year increases in its capital investment program. While we anticipate Exelon's third regulated subsidiary, PECO, to continue being cash flow positive and a reliable source of dividends to the parent, the majority of the common dividend funding will be provided by ExGen during a period when operating margins and related cash flow are expected to decline.

During Exelon's third quarter earnings call (November 1, 2012), management stated that revisiting its dividend policy would be among the range of options for management and the board to consider in preserving its current investment-grade ratings should power prices not recover in the next six months as completely or as rapidly as Exelon's fundamental views suggest. To that end, the rating acknowledges this and other public statements concerning the company's firm commitment to maintain an investment-grade rating at all registrants within the Exelon family.

-Hedging strategies influence cash flow predictability

As an unregulated wholesale energy holding company whose gross margin can be materially impacted by changes in commodity prices, a company's commercial strategy remains an important rating factor. Exelon manages its ratable hedging program over a 36 month cycle with targets of 90% or more of expected generation hedged in the first year, 70-90% in the second year, and less than 50% in the third year. As of September 30, 2012, we understand that Exelon was 88-91% hedged for 2013, 56%-59% for 2014 and 21%-24% for 2015. By completing the merger with CEG, we anticipate that more of the company's electric output will be sold directly to end-use customers through the multiple venues that exist along the retail chain which should reduce the total amount of hedges executed to meet the above coverage targets.

-Competitive position & consistent operations remain long-term strengths

As the largest owner and operator of nuclear generation in the US, Exelon has a strong competitive position and continues to demonstrate an outstanding record as a plant operator, particularly as a nuclear operator. In the intermediate-term, we expect its competitive position to remain largely unchanged as capacity reductions from anticipated coal plant shut-downs in the region should lower reserve margins (and possibly enhance capacity revenues) but are less likely to enhance energy margins given the outlook for natural gas, the fact that most of the plants that will shut down have low capacity factors, and the continuing slow economic recovery. Longer-term, the potential implications of EPA regulations should enhance profitability as any incremental environmental control related costs are likely to result in a higher margin potential for Exelon.

-Regulatory Environment

ComEd operates in an improved, but still challenging regulatory environment for electric utilities in Illinois with some lingering concerns about the framework's predictability. On December 30, 2011, the Energy Infrastructure Modernization Act (EIMA) was signed into law. EIMA established a new formula-rate-plan (FRP) distribution ratemaking paradigm for the state's largest electric utilities and was intended to spur utility infrastructure investment. The legislation requires ComEd to invest $1.3 billion over a five-year period in electric system upgrades, modernization projects, and training facilities along with at least $1.3 billion over a 10-year period in transmission & distribution assets and smart-grid system upgrades. Key aspects of the FRP calculation include cost recovery of the utility's actual capital structure, excluding goodwill; a legislatively-set formula for purposes of calculating the allowed return on equity (ROE); and recovery of pension-related costs.

While passage of EIMA is a credit positive from a cost recovery standpoint, the ICC's implementation of EIMA has been inconsistent supporting our continuing view of a challenging regulatory environment. On May 29th, the ICC ordered a $168.6 million rate reduction premised upon a 10.05% ROE and an 8.16% return on $6.183 billion in rate base. In its order, the ICC rejected ComEd's request to collect a debt-only return on its "pension asset" and adopted the intervening parties' recommendation to rely on an average capital structure and an average rate base calculation in prospective FRP-related revenue requirement reconciliations, versus the language in the law that contemplates the use of year-end values for capital structure and rate base. On September 19th, the ICC reversed its decision on the pension-asset issue but maintained their view concerning on an average capital structure and an average rate base calculation even though the legislation requires year-end capital structure and rate base. ComEd has indicated that continued uncertainty around the implementation of EIMA will influence the speed at which capital infrastructure investment is made in Illinois.

Similarly, we consider the relationship between BGE and the MPSC to be fairly challenging. In order for the CEG merger to be completed, the MPSC required several conditions from Exelon. Among the conditions were that Exelon provide a $100 rate credit to every residential customer 90 days after merger close ($113 million), that Exelon build up to 300 MW of generation within Maryland, that Exelon construct a new office building in Baltimore for its unregulated platform and that Exelon fund a $113.5 million investment in energy efficiency over the next three years. The MPSC also implemented provisions intended to insulate BGE from the rest of the organization, including language that prohibits BG&E from paying a dividend to Exelon through 2014.

On October 22, 2012, BGE updated its application with the MPSC requesting increases of $131 million and $45 million to its electric and gas base rates, respectively, based upon a requested ROE of 10.5%. The new electric and gas distribution base rates are expected to take effect in late February 2013.

In contrast to Illinois and Maryland, we view the regulatory environment in Pennsylvania to be generally credit supportive. This degree of credit supportiveness is exemplified by the reasonable settlements with the PAPUC, including the December 2010 approval of PECO's electric and natural gas distribution rate cases for increases of $225 million and $20 million, respectively.

In February 2012, the state's governor signed into law (Act 11) a measure that would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems. To qualify for the DSIC, utilities are required to submit a long-term infrastructure improvement plan, which will be reviewed by the PAPUC every 5 years, and a certification that a base rate case has been or will be filed within 5 years. The DSIC cannot exceed 5% of distribution rates and will be reset to zero if the utility's return on equity exceeds the allowable rate of return under the DSIC. The law also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the future test year. On August 2nd, the PAPUC issued a final order that implements portions of Act 11, which among other things, provides for a DSIC for electric, natural gas, water and wastewater utilities. We view the terms of this legislation as supportive to utility credit quality.

For more information on ComEd, PECO, and BGE, please refer to their credit opinions which can be found on moodys.com.

Liquidity

Overall, we believe that Exelon has good liquidity. For fiscal year 2011, we calculate that Exelon generated about $4.853 billion of cash from operations, which covered 84% of the $4.4 billion of capital outlays (including acquisitions of $387 million) and $1.4 billion of dividends, resulting in negative free cash flow of around $582 million on a consolidated basis.

Beginning in 2013, Exelon's liquidity arrangements supporting its unregulated power business will equal $6.1 billion, a decline of $4.2 billion from the $10.3 billion level that existed immediately following merger close. This decline, while substantial on a notional basis, is largely reflective of the reduced collateral requirements that occurs when a company that is long on generation is combined with one that has a large retail network. At October 24, 2012, there was $4.2 billion of availability under the $6.1 billion in Exelon and ExGen aggregated facilities, after giving effect to $1.9 billion of ExGen letters of credit issued. At October 24th, Exelon and ExGen had no commercial paper outstanding. The $6.1 billion of credit facilities that supports Exelon's unregulated power business expires in August 2017. The separate legacy CEG $1.5 billion credit facility, which was assumed by Exelon at merger close and unutilized at October 24th, will expire at year-end 2012.

On the regulated side, a total of $2.2 billion of credit facilities remain in place for working capital requirements. ComEd has an unsecured credit agreement totaling $1 billion that expires March 2017 while PECO and BGE each have separate $600 million revolving credit facilities that expire in August 2017. At October 24, 2012, no utility commercial paper was outstanding. However, there was $121 million of letters of credit issued under ComEd's $1 billion (leaving availability at $879 million and there was $1 million of letters of credit issued under each of PECO's and BG&E's $600 million credit facilities).

The core syndicated credit facilities at Exelon and its subsidiaries are used primarily to provide liquidity support and for the issuance of letters of credit. While the credit agreements do not contain any rating triggers that would affect borrowing access to the commitments and do not require material adverse change (MAC) representation for borrowings or the issuance of LOCs, there is a financial covenant for each entity, all of which are compliant.

In the event that ExGen were downgraded below investment grade, ExGen could be required to post additional collateral of $2.0 billion at September 30, 2012. If ComEd was downgrade below investment grade, it would be required to post $218 million at September 30, 2012. If PECO and BG&E were each downgraded to below investment grade, they would have been required to post $31 million and $54 million, respectively, of additional collateral at September 30, 2012.

During 2012, Exelon and its subsidiaries were active issuers of long-term capital market debt. On June 18, 2012, ExGen issued $775 million of senior unsecured notes, including $275 million of 4.25% notes due 2022 and $500 million of 5.60% notes due 2042. Concurrent with the new debt issuance, ExGen announced an exchange offer of Exelon's 7.6% $700 million senior unsecured notes due 2032 (formerly CEG obligations assumed by Exelon) into either the newly issued ExGen 4.25% senior unsecured notes due 2022 or ExGen's 5.60% senior unsecured notes due 2042. ExGen purchased $442 million of the old notes in exchange for issuing $537 million of senior unsecured notes due in 2022 and 2042, plus a cash payment of approximately $60 million.

In addition to the above, in August 2012, BGE issued $250 million of 2.8% senior unsecured notes due 2022, in September 2012; PECO offered $350 million of 2.375% first mortgage bonds due 2022; and in October 2012, ComEd issued $350 million of 3.8% first mortgage bonds due 2042.

At September 30, 2012, Exelon had $1.602 billion of consolidated cash, of which $732 million resided at ExGen and $800 million with the regulated utilities. The substantially higher than normal cash balances at the utilities reflect August and September financings which prefunded upcoming debt maturities at BG&E and PECO. During the second quarter of 2012, Exelon made a $66 million equity contribution to BGE to fund the after-tax amount of the $113 million rate credit pursuant to the MPSC order.

Structural Considerations

Within the last several years, Exelon has refinanced holding company debt with debt issued at ExGen. Exelon currently has $1.3 billion of remaining holding company debt, $800 million that matures in 2015 and $500 million that matures in 2035. Additionally, at merger close, Exelon legally assumed the obligations of CEG's publicly-held debt, guarantees and other contracts at merger close adding $1.8 billion of senior debt and $450 million of subordinated debt to Exelon. As mentioned previously, $442 million of the old notes were exchanged into $537 million of ExGen securities. For these reasons, when evaluating ExGen, Moody's examines historical and projected financial metrics for ExGen with the debt of Exelon holding company incorporated into the analysis.

Rating Outlook

The negative rating outlook for Exelon factors in the expected decline in certain key credit metrics that we anticipate occurring over the intermediate-term due to sustained weak market fundamentals even with the decline in growth capital spending. The negative outlook also acknowledges that, despite the low-cost fleet, we believe the unregulated segment would need to experience some increase in power prices above current market forwards in order to generate metrics consistent with their current rating category. The negative rating outlook further considers the sizeable dividend requirements at Exelon along with the parent's heavy reliance on the large unregulated platform which can add to cash flow volatility.

What Could Change the Rating - Up

In light of the negative rating outlook, the ratings at Exelon are not likely to be upgraded in the near-term. The rating outlook could, however, stabilize if the company continues to take actions that we believe are supportive of sustained long-term credit quality, particularly as it relates to capital allocation decisions.

What Could Change the Rating - Down

The rating could be downgraded if future capital allocation decisions result in higher than anticipated negative free cash being financed with incremental indebtedness. Specifically, management has stated their intention to examine future dividend policy in light of ongoing power prices; thus, if power price expectations remain subdued and the current dividend policy is not reevaluated, or if the modification is only modest despite relatively sustained weaknesses, the ratings are likely to be downgraded.

Other Considerations

Given the size of the unregulated revenues, earnings, and cash flow, Moody's evaluates Exelon's financial performance relative to the Unregulated Utility and Power Company methodology and, as depicted below, Exelon's indicated rating under the grid based on historical results and from projected results (next 12-18 months) is Baa2.

Rating Factors

Exelon Corporation

Power Companies [1][2]	**LTM09/30/2012**			**Moody's 12-18 month Forward View* As of November 2012**	
Factor 1: Market Assessment, Scale and Competitive Position (20%)	**Measure**	**Score**		**Measure**	**Score**
a) Market and Competitive Position (15%)		A			A
b) Geographic Diversity (5%)		Baa			Baa

Factor 2: Cash Flow Predictability of Business Model (20%)				
a) Hedging strategy (10%)		Ba		Baa
b) Fuel Strategy and mix (5%)		Ba		Ba
c) Capital requirements and operatinal performance (5%)		Baa		Baa
Factor 3: Financial policy (10%)		Ba		Ba
Factor 4: Financial Strength - Key Financial Metrics (50%)				
a) CFO pre-WC + Interest / Interest (15%) (3yr Avg)	7.3x	A	7.0 - 7.5x	A
b) CFO pre-WC / Debt (20%) (3yr Avg)	32.4%	Baa	25 - 30%	Baa
c) RCF / Debt (7.5%) (3yr Avg)	28.0%	A	13 - 17%	Baa
d) FCF / Debt (7.5%) (3yr Avg)	3.2%	Ba	(10) - 0%	B
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

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

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 09/30/2012(L); Source: Moody's Financial Metrics

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INDUSTRY OUTLOOK

US Regulated Utilities:

Regulatory Support, Low Natural Gas Prices Maintains Stability

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Our outlook for the investor-owned US regulated electric and gas utility sector is stable. This outlook reflects our expectations for the fundamental business conditions in the industry over the next 12 to 18 months.

» **The outlook for the US investor-owned regulated electric and gas utility sector is stable.** We expect a supportive regulatory environment to remain intact over the next 12 to 18 months, providing a timely recovery of prudently incurred costs and investments through authorized rates. We see a sustained period of low natural gas prices benefitting utilities seeking other rate base increases; steady and stabilizing financial ratios, and average annual revenue increases between 3-5%.

» **Capital markets remain highly accessible.** The sector benefits from flight-to-quality dynamics, with a return to long-term liquidity facilities as the norm.

» **We expect high capital expenditures to continue for the foreseeable future.** Large capex will contribute to rate base growth; however, management must carefully address the financing of corresponding negative free cash flow, along with the increased rate pressure on customers.

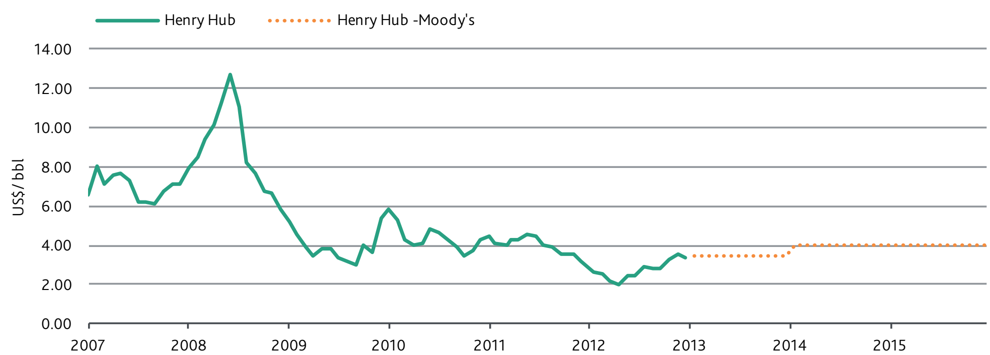
» **States to watch in 2013.** We see regulation throughout the US in a business-as-usual status over the near-term, but there are certain states where our perception of regulatory supportiveness may change in 2013. States we view as prone to positive changes are Maryland, Arizona, New Mexico and Texas. States we view as prone to negative changes are the eastern states impacted by Hurricane Sandy, Illinois, North Carolina, Ohio and Mississippi. We also see potential for negative changes at the FERC.

» **We anticipate financial metrics stabilizing over the near term.** Cash recovery of costs through special recovery mechanisms and the extension of bonus depreciation should help to offset reduced allowed returns on equity (ROE) and low customer demand. Companies pursuing large capex plans will see a decline in financial metrics and are at the highest risk for recovery delays.

Low natural gas prices continue to benefit utilities, customers and commissions

The abundant supply of domestic natural gas is a material credit positive for regulated utilities. Low natural gas prices have facilitated an easing of fuel costs and power prices throughout the nation and should continue to provide a backdrop for continued supportive regulatory relationships over the next 12-18 months. The proliferation of shale gas supplies in the US has driven natural gas prices to new lows as seen in Figure 1, below. This phenomenon, in combination with low customer demand due to a sluggish recovering economy, mild weather and the effects of energy efficiency and demand side management (DSM), has kept power prices low - a trend we expect to persist through 2013.

FIGURE 1
Natural Gas Prices and Assumptions[1]



Source:EIA.gov and Moody's

Since a peak of over $12 per MMBtu in 2008, gas prices have been on a rather steady decline. Since fuel and purchased power costs represent the single largest utility cost, and are typically a direct pass-through to rate payers, customer bills benefit significantly from reduced commodity and procurement costs.

These variable cost decreases have provided headroom in rates, enabling regulators to allow utilities to recover rising non-fuel costs through increases in base rates without a material change to the aggregate amount of a customer's bill. The offset of fixed cost increases, with variable cost decreases, is largely unnoticed by the typical residential consumer. The cost offset helps to avoid any negative customer reaction that might place political pressure on utility commissions and lead to their reluctance to allow some general rate increases for utilities.

Figure 1 also reflects our belief that the cost environment for natural gas will be low for several years. We expect this environment to give regulators additional flexibility in maintaining their support for the recovery of rising utility operating costs. Our natural gas price expectations are influenced by our view that a sudden "game-changing" growth spurt in demand is unlikely over the near term and that a gradual increase in gas consumption will occur throughout all corporate sectors in 2013. Our price assumptions show Henry Hub natural gas at $3.50 per MMBtu for 2013 and at $4.00 thereafter.

[1] Our natural gas price assumptions are derived from the Moody's energy team and its Global Oil and Natural Gas outlook. These price assumptions are used for rating purposes and as sensitivity inputs for production companies' projected performance.

Low commodity prices benefit industry liquidity

Low commodity costs have also bolstered utility liquidity profiles, as reduced collateral calls and inexpensive hedges are increasingly replacing historical positions. The sector continues to benefit from open and welcoming credit markets, as utilities remain a safe haven for investors looking for steady and predictable returns. Furthermore, bank support via long-term credit facilities (e.g., 5 year tenors) has returned, following a contraction during the Great Recession.

We expect the industry axiom of open and welcoming markets to continue over the next 12 to 18 months; however, the flight from trouble in Europe may have potentially run its course, and Basel III requirements on bank capital may weaken the appetite of lender interest in the sector. Since the next round of refinancing may be more expensive, it will provide an indication of which issuers refinance only opportunistically and which issuers refinance because maintaining longer-term liquidity is a core tenet of their financial policy.

Regulatory support is a credit positive, despite lower authorized ROEs

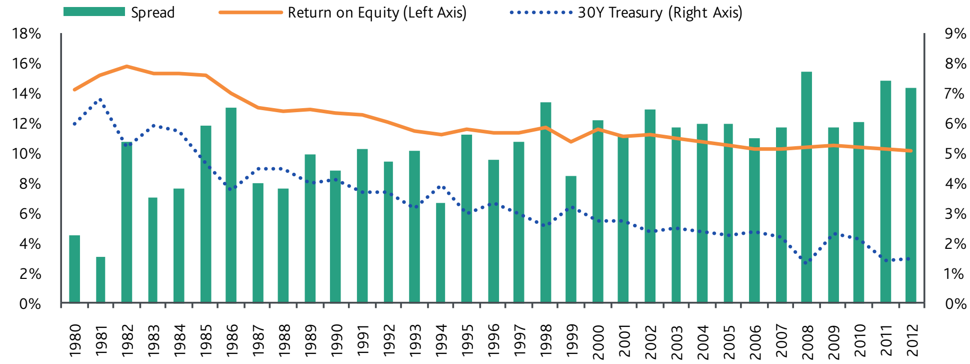
Given the headroom created by lower fuel and purchased power costs, regulatory support for general rate increases has continued throughout the nation with few states generating any prospect of immediate concern. The general trend for approved rate increases in the US were 61% of requested amounts granted in 2012, compared to 55% in 2011 and 57% in 2010. Our ongoing premise is that regulatory commissions prefer to regulate financially healthy utilities and that utility managements have core competencies in navigating the regulatory landscape, in order to support the long-term financial wellbeing of the companies.

One point of interest to note is in the trend of falling allowed ROEs throughout the industry, which includes several jurisdictions recently crossing below the 10.00% threshold. For example, several issuers in Oregon (Northwest Natural Gas, A3, negative and Idaho Power, Baa1, stable) and Washington (Puget Sound Energy, Baa2, stable and Avista Corp. Baa2, stable) dropped below 10.00% allowed ROE in 2012, with some companies experiencing sub-10.00% allowed ROE in multiple jurisdictions, such as PacifiCorp (Baa1, stable) and Kansas City Power & Light (Baa2, stable - its Missouri rate case decision occurred in January 2013). According to SNL Financial, the average allowed ROE for investor owned utilities, has dropped to 10.07% in 2012 versus 10.21% in 2011. We have observed two oft-cited reasons behind a commission reducing a utility's allowed ROE; those being 1) the prevalence of single item rate making through specific riders and trackers, and 2) the current low interest rate environment.

Many commissions have reasoned that a heightened use of special cost recovery mechanisms such as environmental cost trackers, weather normalization adjustments, decoupling mechanisms, and the like, have reduced the business and financial risk of a utility, thus justifying a reduction in allowed ROE.

Similarly, various commissions cite that due to the current low interest rate environment, a utility's cost of capital has been reduced to a point that warrants a lower allowed return and reduced rates for customers. Figure 2 identifies the declining ROE trend in recent years, compared to the risk free rate of return on the 30 year US Treasury bill.

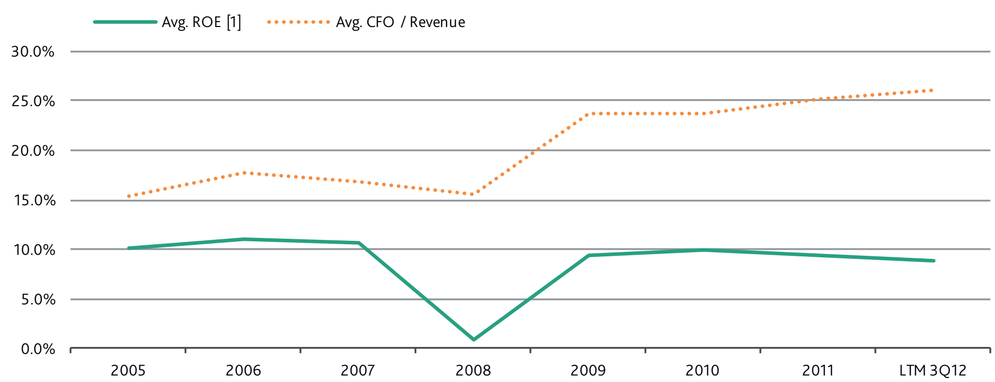
FIGURE 2
Authorized Returns on Equity, Treasury Rates and Spread



Source: SNL & Bloomberg

We expect the risk free rate of return to remain low through 2014 and that pressure on ROEs will persist over the near-term. Despite this trend, we see evidence of cash recovery being sufficient to sustain most utility financial profiles over the next 12 to 18 months. In Figure 3 below, we observe that although ROE has declined over the past two years, cash flow from operations (CFO) as a percentage of revenue has actually increased, potentially due to enhanced cost recovery provided by trackers and certainly from federal tax incentives such as accelerated bonus depreciation.

FIGURE 3
Cash Generation versus Returns



[1] 2008 Moody's Adjusted Net Income experienced significant reductions due to large losses in pension plan assets for several companies in our peer group.

Source: Moody's

If cash recovery is maintained near current levels, despite minor reductions in ROE, there should be no negative impact on ratings. However, declining allowed ROE levels are negative because we often regard the level of allowed ROE as a barometer of the relationship that a specific utility maintains with its commission. Thus we view punitive reductions to ROE as a credit negative, although the immediate impact is usually delayed, somewhat, by continued growth in rate base. Furthermore, we could see negative rating actions if ROEs were to decline to levels near 9.00%, as reduced revenues will eventually lead to declines in cash flow, or turn investor interest toward competing utilities in more investor-friendly jurisdictions, or even to different sectors.

Our primary concern about the trend toward lower industry ROEs is the eventual return of higher interest rates without the benefit of timely and commensurate adjustments toward higher allowed ROEs. That is, when the relationship between interest rates and ROEs starts to converge (identified by the green columns in Figure 2), there is risk for credit deterioration and negative rating impacts.

We view regulatory compacts that have annual updates to ROEs, such as the historical multi-year rate plans evidenced in states like New York and Vermont, to be more credit supportive in circumstances of a rising interest rate environment. The allowed ROEs in the historical rate plans of these states are formulaic, with treasury bill rates as an automatic input to the outcome of an allowed ROE. They also contain annual rate increases to capture rising costs and investment for the respective utility. Conversely, in states where there are several years between rate cases, there is a higher risk of allowed returns lagging interest rate growth and achieving all-in rates that do not reflect the reality of a more costly economic environment.

States to watch in 2013

Although our general view of regulation throughout the US is business-as-usual over the near-term, there are certain states where our perception of regulatory supportiveness may change in 2013. Figure 4 identifies those states we view a change in the current regulatory environment, either positive or negative, as a real possibility in 2013, with a bias to the negative. We also describe the circumstances motivating our vigilance in these states.

FIGURE 4

Potential Shifts in Regulatory Support

Positive Potential		Negative Potential	
State	Comment	State	Comment
MD	Governor recently wrote to Maryland Public Service Commission urging them to adopt a task force recommendation to allow cost recovery mechanism for investments aimed at improving reliability of a utility's distribution system.	NY, NJ, CT	Effects of Hurricane Sandy and potential for deferred recovery of costs and heightened political influence over rate making.
AZ	UNS Gas, Arizona Public Service, and Southwest all recently received credit supportive rate case outcomes and included shorter time frames for deciding cases and decoupling. Positive outlook for UNS Energy and subsidiary Tucson Electric Power (TEP) reflects our expectation for a reasonable outcome in upcoming TEP rate case.	IL	Although recent legislation has improved Commonwealth Edison and Ameren Illinois' cost recovery prospects, the regulatory and political environment remains unpredictable with adverse regulatory decisions continuing to be a continuing trend.
NM	The state recently finalized rules allowing rates to be based on a forward looking test year, but these new rules have yet to be implemented in a rate order. The legislature is also expected to promulgate rules following a recent referendum requiring more stringent qualifications for elected commissioners.	NC	At Duke Energy, management changes and other developments following the Progress Energy merger and a subsequent settlement with North Carolina Utilities Commission has increased regulatory risk at a time when both of its North Carolina utility subsidiaries are pursuing rate cases.

FIGURE 4

Potential Shifts in Regulatory Support

Positive Potential		Negative Potential	
TX	Political and regulatory intervention seeks to alter the market structure to benefit generators.	OH	Although Electric Security Plans provide some clarity through 2014, the market transition toward fully deregulated generation could negatively affect utility financials.
		MS	Unanimous Mississippi Public Service Commission vote to deny Mississippi Power's request of financing costs on Kemper County IGCC plant due to a pending Sierra Club lawsuit was a credit negative. A settlement agreement on cost recovery has since been reached.
		FERC	Changes already enacted to the FERC rate making methodology in California and the current legal battle regarding New England transmission ROE reductions threaten pervasive changes to the degree of financial support offered by the FERC.

Stable financials, but falling cash flow ratios for big spenders

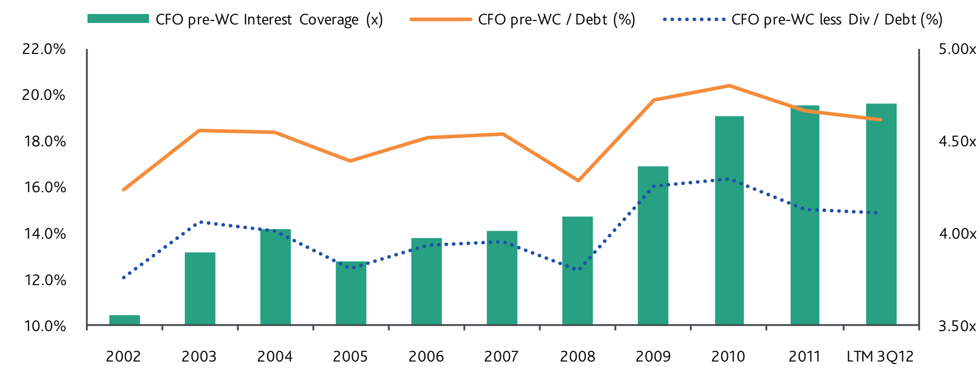
In recent years, utilities have elected to take advantage of favorable tax policies which boost near term cash flow in exchange for reduced rate base growth in the future – specifically, bonus depreciation. This voluntary tax election also benefits utilities because it temporarily boosts key financial metrics such as CFO pre-WC to debt[2] and CFO pre-WC interest coverage. Since 2009, tax policy changes such as those associated with accelerated bonus depreciation, uniform capitalization and capitalized repairs have provided the industry with one-time changes to tax accounting methods that have generated significant amounts of cash flow from tax savings or refunds.

We estimate that, on average, a utility company's cash flow to debt metric benefitted anywhere from 200 to 300 basis points in any given year (2009-12), depending on the timing of when a given company exercised accounting methodology changes. Although these one-time effects have largely run their course, we note that the recent extension of 50% bonus depreciation will continue to support (or inflate, if comparing to organic run-rate potential) cash flow levels in 2013.

As seen in Figure 5, even with benefits from 100% bonus depreciation in 2011 and 50% in 2012, cash flow coverage of debt has declined for our peer group since the height of 2010.

[2] Cash Flow from Operations before Working Capital to debt

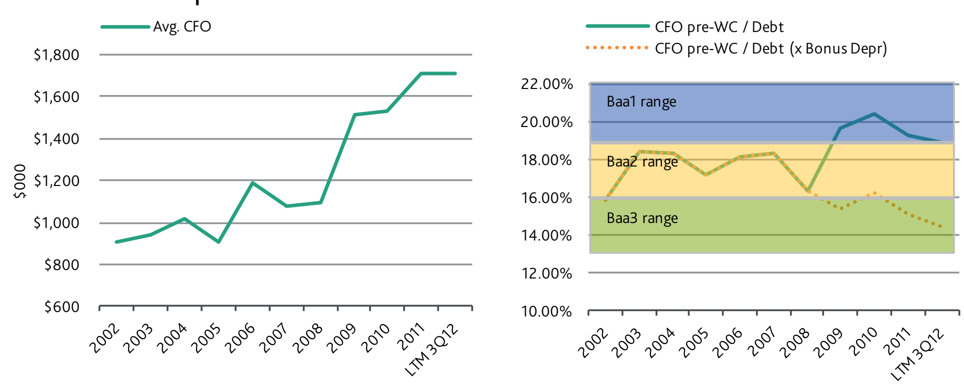
FIGURE 5
Key Cash Flow Metrics



Source: Moody's

This inflation due to one-time benefits is a risk, as utilities will likely have lower cash flow when bonus depreciation ends, all else being equal. In Figure 6, we estimate the magnitude of the effects of bonus depreciation (assuming 70% of capex represents qualifying assets and a 35% tax rate) on the peer group's CFO pre-WC to debt. Without bonus depreciation, the financial profile of the group falls from a level in-line with the low Baa1 rating range of our Regulated Electric & Gas rating methodology, to a level solidly in the Baa3 range.

FIGURE 6
Effects of Bonus Depreciation



Source: Moody's

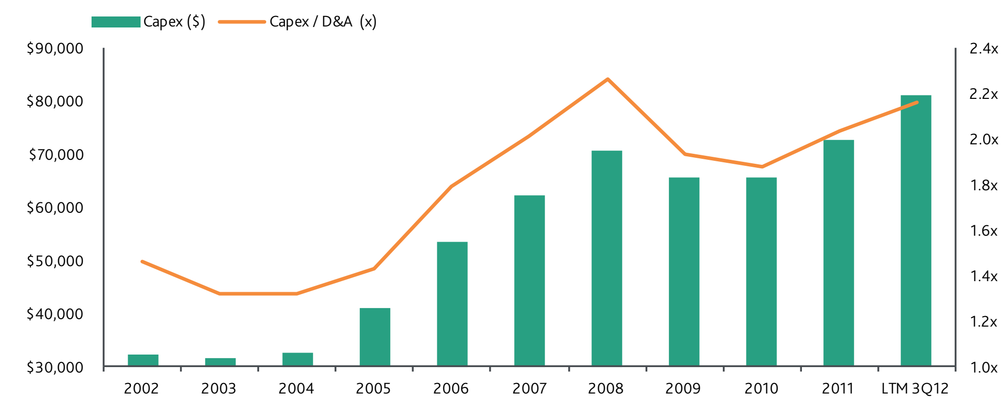
Nevertheless, we expect financial metrics to remain relatively steady in 2013, given our assumptions of ongoing rate relief, the continuance of low interest rates, cash flow stability provided by cost recovery mechanisms, government policy from the extension of bonus depreciation, and the potential for the Moving Ahead for Progress in the 21st Century Act (MAP-21) to reduce the funding requirements for pension obligations. More importantly, we think managements will utilize a balanced mix of debt and equity to keep the leverage and capitalization of their utilities in a conservative range and not test negatively biased rating actions.

Although we expect metrics for the industry to be stable, companies with robust capital programs, such as Virginia Electric and Power Company (A3, stable), Indiana Michigan Power company (Baa2, stable), SCANA Corporation (Baa3, stable), and Public Service Company of Oklahoma (Baa1, stable), could experience a decline in financial metrics due to increased debt associated with growing free cash flow deficits. In each of these cases, we anticipate that the resulting financial profile will still be appropriate for each company's current rating.

Rate shock and regulatory contentiousness are primary risks to stable outlook

Capital expenditure plans for most US utilities have rapidly outpaced depreciation and amortization (D&A) levels in recent years. The need for environmental retrofits, growth in renewable energy use and basic system maintenance and upgrades are the primary drivers for the capex growth trend observed amongst our sample utility peer group (made up of 45 industry peers; see Appendix A). Figure 7 shows the relationship between capex and D&A over the past ten years for these companies.

FIGURE 7
Capex Levels for Moody's Peer Group
($ millions)



Source: Moody's

We view capital investment in rate base positively over the longer term, as it contributes to growth in operating cash flow. Given the low commodity price environment, we assume that these growth investments will be recovered through base rate cases on a timely basis without contentious regulatory proceedings. However, given the magnitude of these investments, corresponding increases in customer bills and associated financing needs, we see the need for each company to carefully execute their capital raising strategies in order to maintain stable credit profiles across the sector. We view the relationship between rising customer bills and the current economic environment as a potential credit negative. While the risk of this scenario (i.e., significant rate shock) is considered to be remote, if there were a reversal in the plodding economic recovery, and lower variable costs were no longer sufficient to offset the higher costs of capex programs, recovery of these costs could be delayed over the intermediate-term in order to avoid customer rate shock and/or rate fatigue.

In order to gain an appreciation for the magnitude of these prospective risks, we analyzed the potential rate impact of expected capex levels for companies involved in large capital programs. Figure 8 shows the utilities that we believe have the largest potential rate increases over the near-term. The analysis includes 2013-2014 capex data made available in 2011 10K company disclosures and assumptions explained in Appendix B (also see our report "High Capital Expenditures Adding to Rate Pressure for Utilities" (October 2012)). Although the time horizon of the capital expenditures extends outside of our outlook horizon, we find it valuable to determine what companies will require substantial rate increases to recover capital expenditures, in order to monitor management's near-term response to mitigate and/or absorb future risks to rate recovery. Proactive management strategies, in our opinion, include implementing cost cutting measures, strengthening the balance sheet and bolstering liquidity. Several of these utilities were recently awarded increases in rate cases that were determined in late 2012.

FIGURE 8

Largest Potential Rate Increases

Company	Rating	Total Rate Increase for 2013-2014 Spending	Estimated Capex 2013-2014 (millions)	CFO pre-WC / Debt LTM 3Q12	Projected CFO pre-WC / Debt 2014	Metric Cushion	Supportiveness of Regulation
Louisville Gas and Electric	Baa1	18%	$1,538	27%	23%	7%	Above Average (A)
Mississippi Power	A3	18%	$1,235	14%	16%	-4%	Above Average (A)
South Carolina Electric & Gas	Baa2	12%	$2,600	17%	17%	0%	Above Average (A)
Kentucky Utilities	Baa1	11%	$1,583	23%	21%	5%	Above Average (A)
Southwestern Public Service	Baa2	11%	$1,160	24%	22%	6%	Average (Baa)
PPL Electric Utilities	Baa2	10%	$1,689	22%	21%	5%	Average (Baa)

Source: SNL, 10K and EIA filings, Moody's

Over the next two years, some of these companies could find themselves poorly positioned within their rating category as a result of their cash outlay. Although we assume a 50% debt financing of these expenditures, negative ratings action could occur if management takes a more aggressive leverage policy or if cash flow recovery is slower than expected. Thus, attention will be given to the progress of each company's capex program and the regulatory developments that dictate the timing and duration of recovery.

Utilities will need to manage continued flat volume growth due to economy, energy efficiency and demand side management

Another key to our outlook assumptions is the industry's ability to pass through base rate increases (aided by low commodity costs) without the benefit of robust organic growth in customers or usage per customer. Flat to declining demand (see Figure 9) represents yet another key risk to the stability of our outlook, as it places the full amount of rising cost pressure on a static amount of customer use.