BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Progress Energy Florida, Inc.

Docket No. 090079-EI

Submitted for filing: August 31, 2009

REBUTTAL TESTIMONY OF

THOMAS R. SULLIVAN

On behalf of Progress Energy Florida

REBUTTAL TESTIMONY OF

THOMAS R. SULLIVAN

I. Introduction and Purpose of Rebuttal Testimony.

Q. Mr. Sullivan, did you file direct testimony in this proceeding?

A. Yes, I did.

Q. What was the purpose of your direct testimony?

A. The purpose of my direct testimony was to address Progress Energy Florida, Inc.'s ("PEF's" or the "Company's") capital structure and its requirements to ensure that it maintains continuous access to capital markets to obtain capital at a reasonable cost when that capital is needed to meet our customers' energy needs.

Q. Have any of the intervenor witnesses addressed PEF's capital structure or other issues that would impact the Company's ability to maintain continuous access to the capital markets at reasonable costs?

A. Yes, they have. Dr. Woolridge, Mr. Lawton and Mr. Schultz, on behalf of the Office of Public Counsel ("OPC"), and Mr. Pollack, on behalf of the Florida Industrial Power Users Group ("FIPUG"), have all filed testimony related to either capital structure or other issues, such as return on equity or cost of debt, that impact the Company's financial position and its ability to maintain access to the capital markets at reasonable costs.

Q. Have you read their testimony?

A. Yes, I have.

Q. What is your understanding of the intervenors' recommendations regarding PEF's capital structure and cost of capital, as well as their assessment of the impact of those recommendations on the Company's credit rating and financial health?

A. Dr. Woolridge and Mr. Pollack disagree with the Company's capital structure, recommending a common equity ratio of 50%. Dr. Woolridge also recommends a cost of equity of 9.75%, a short-term debt cost rate of 3.06% and a long-term debt cost rate of 6.05%. All of the intervenors believe that their recommendations, including the pre-tax cash flow impact of the $149 million adjustment to the depreciation reserve and the total $35 million reduction in base rates, would not negatively impact the Company's credit rating or its ability to access the capital markets at reasonable costs.

Q. Did any intervenors question the positions in your direct testimony regarding the importance of the Company strengthening its financial profile or achieving a consistent target credit rating of mid-single A?

A. No, they did not.

Q. Do you agree with the intervenors' recommended adjustments to PEF's proposed return on equity, capital structure and cost of debt, and the associated impact of those adjustments on PEF's credit rating and financial health?

A. No, I do not. In the testimony that follows, I will describe why I disagree with the intervenors' recommended adjustments to PEF's cash flow, return on equity ("ROE"), capital structure and cost of debt. Most importantly, I will discuss how the adjustments would negatively impact the Company's ability to maintain and improve its financial strength. This, in turn, would limit the Company's ability to access capital in order to provide reliable energy for its customers at a reasonable cost. The intervenors' recommended changes would represent a material change from the historically constructive regulatory environment in Florida, and would be viewed negatively by the financial markets. It is critical for PEF to maintain a strong financial position while meeting the growing needs of its customer base and increased environmental compliance, including the reduction of carbon emissions with the planned construction of nuclear generation. I believe the successful implementation of PEF's plans to achieve these goals will require the return on equity and cost of debt capital we originally requested, along with a strong capital structure. Without these, both the Company and its customers will be adversely impacted.

Q. How is your testimony organized?

A, First, I will address the cost of equity recommendation of Dr. Woolridge and its potential impact on the Company if adopted. I will then address the overall implications of the intervenors' combined recommendations on cash flow, and how

they would hurt the financial position of the Company and negatively impact customers. I will then address the intervenors' recommendations regarding capital structure, their assertions regarding PPAs, and their recommendations for the cost of short-term and long-term debt.

Q. Do you have any exhibits to your rebuttal testimony?

A. Yes. I have the following exhibits to my rebuttal testimony:

- Exhibit No. __(TRS-13), Moody's Report "Industry Outlook: U.S. Investor-Owned Electric Utilities," January 2009;
- Exhibit No. __(TRS-14), Fitch's Report "U.S. Utilities, Power and Gas 2009 Outlook," December 2008;
- Exhibit No. __(TRS-15), Moody's Report "Rating Methodology: Regulated Electric and Gas Utilities," August 2009;
- Exhibit No. __(TRS-16), Fitch's Report "EEI 2008 Wrap-Up: Cost of Capital Rising," November 2008;
- Exhibit No. ___(TRS-17), Standard & Poor's ("S&P") Report "Credit FAQ: Top 10 Investor Questions for the U.S. Electric Utility Sector in 2009," January 2009;
- Exhibit No. __ (TRS-18), Moody's Credit Opinion: Progress Energy Florida, Inc., June 2009;
- Exhibit No. __ (TRS-19), PEF 2010 Adjusted Credit Metrics Chart;
- Exhibit No. __(TRS-20), "The A Rating," by Steven M. Fetter, Electric Perspectives, May/June 2009;

- Exhibit No. __(TRS-21), Moody's Report "Special Comment: New Nuclear Generation: Ratings Pressure Increasing," June 2009;
- Exhibit No. __(TRS-22), Fitch's Report "U.S. Electric and Gas Financial Peer Study," June 2009;
- Exhibit No. __(TRS-23), S&P's Report "Request for Comments: Imputing Debt To Purchased Power Obligations," November 2006;
- Exhibit No. __ (TRS-24), S&P Ratings Direct – Florida Power Corp. d/b/a Progress Energy Florida, Inc. credit report, June 2009;
- Exhibit No. __ (TRS-25), S&P Ratings Direct – Florida Power Corp. d/b/a Progress Energy Florida, Inc. credit report, May 2008; and
- Exhibit No. __ (TRS-26), Composite Exhibit of Forward 3-month London Interbank Offered Rate ("LIBOR") and 10-year and 30-year Treasury Note and Bond Forecasts.

These exhibits were either prepared by me or at my direction or they are industry information that I regularly obtain and review as part of my responsibilities as the Treasurer for PEF. They are true and correct.

II. Cost of Equity.

Q. Do you believe Dr. Woolridge's recommended ROE of 9.75% is appropriate for PEF?

A. No, I do not. The Company hired a well regarded witness, Dr. James A. Vander Weide, to recommend the appropriate return on equity for PEF. I have read and support Dr. Vander Weide's recommendation of a 12.54% ROE and believe it should

be adopted by the Commission. Dr. Vander Weide will address the more technical aspects of Dr. Woolridge's recommendation, but I will address the overall reasonableness of the recommendation and its potential impact on the Company.

Q. Is Dr. Woolridge's recommended ROE consistent with other utilities in the southeast?

A. No, it is not. Tampa Electric was recently awarded a return on equity of 11.25% in 2009 by the Commission. When compared to Tampa Electric, PEF has additional risk factors including a much larger generating fleet that includes nuclear operating risk with our Crystal River Unit 3 ("CR3") nuclear power plant. In addition, PEF is moving forward with the construction of new nuclear power plants, and other large capital expenditure projects which significantly increase PEF's risk profile over Tampa Electric's and nearly every other electric utility's risk profile within the state. These additional risk factors translate into a higher cost of capital, which supports PEF's request for a higher return on equity than that awarded to Tampa Electric. In their June 2009 credit opinion for PEF, Moody's stated that the FPSC's decision in Tampa Electric's rate case "affirmed Moody's view that the regulatory environment for electric utilities in Florida has remained relatively supportive" (Exhibit No. __(TRS-18) to my rebuttal testimony). Providing PEF a lower return on equity than that awarded to Tampa Electric would be viewed as inconsistent and negative by the rating agencies and financial community and begin to raise doubts as to the regulatory climate in the state of Florida.

Dr. Woolridge's recommended ROE is also below other authorized ROEs for utilities in the southeastern United States, including Alabama Power (13.75%), Georgia Power (11.25%), Gulf Power (12.0%) and Progress Energy Carolinas, Inc. (12.75%). In addition, the Commission issued an order last year recognizing a 11% ROE for Florida Public Utility Company, which is a distribution only utility. These are all companies that compete with PEF for investor dollars needed to provide reliable electric service and fund capital expenditure plans at reasonable costs.

Q. What would be the implications to PEF if Dr. Woolridge's recommended ROE of 9.75% were adopted?

A. The ROE recommended by Dr. Woolridge would be a significant change from the historically supportive regulatory environment in Florida. The financial markets view this supportive regulatory environment as a critical element of the relationship between utilities, regulators and customers. In their January 2009 report titled "Industry Outlook: U.S. Investor-Owned Electric Utilities," Moody's states the following:

> "We continue to incorporate a view that individual state regulatory authorities will provide reasonably timely recovery of prudently incurred costs and investments. Moreover, we continue to believe that regulators prefer to otherwise regulate financially healthy companies. This relationship often creates a virtuous cycle, where financially healthy utilities have the balance sheet strength and liquidity to assure investment, maintain high levels of

reliability and attract economic development. In turn, this tends to facilitate contentment among consumers, legislators and regulators."

See Exhibit No. ___ (TRS-13) to my rebuttal testimony. Dr. Woolridge's proposed cost of equity would put PEF at a significant disadvantage in its competition for capital with other companies with similar risk profiles and would not be adequate to maintain access to capital markets at reasonable prices. When competing for capital with the southeastern utilities with higher allowed ROEs referenced above, PEF would be viewed as a less attractive investment. Investors would not invest in a company earning a lower ROE when they could invest in other companies of similar risk and earn a higher ROE.

PEF's operating cash flow would also be reduced, hurting investor confidence and likely resulting in a credit rating downgrade. The Company's ability to raise the capital necessary to meet customer needs would be hurt, and the cost of that capital would be higher. This position was summarized by Fitch in their December 2008 report titled "U.S. Utilities, Power and Gas 2009 Outlook" (Exhibit No. ___(TRS-14) to my rebuttal testimony):

"All else equal, utilities operating in more balanced regulatory jurisdictions providing high-quality customer service are more likely to earn reasonable returns on investment and achieve higher creditworthiness. Conversely, utilities with suboptimal regulatory outcomes are more likely to experience lower relative returns, higher financing costs and relatively anemic credit profiles."

Lower credit ratings would also jeopardize the Company's ability to reduce fuel cost volatility through hedging, as the Company might not meet minimum credit standards required by counterparties. Access to capital required for immediate service restoration following storms could also be impacted by lower credit ratings. All of these negative ramifications from adopting the recommended ROE would severely impact the Company's ability to serve its customers effectively and would ultimately result in higher rates.

Q. Why do you believe the adoption of Dr. Woolridge's recommended ROE would likely result in lower credit ratings?

A. The regulatory framework and financial performance of a company are critical to the assessment of a utility's credit quality by the rating agencies. In their ratings assessment process, Moody's, for example, focuses on four key rating factors that are central to the assignment of ratings for companies in the regulated electric and gas utilities sector: (1) regulatory framework; (2) ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. The process is outlined in the Moody's report "Rating Methodology: Regulated Electric and Gas Utilities" issued in August 2009. See Exhibit No. ___(TRS-15) to my rebuttal testimony. The adoption of Dr. Woolridge's recommended ROE would hurt PEF's position in the first, second and fourth criteria listed above.

Fitch also places emphasis on the regulatory framework in determining credit quality. In their November 2008 report titled "EEI 2008 Wrap-Up: Cost of Capital

Rising" (Exhibit No. ___ (TRS-16) to my rebuttal testimony), Fitch states the following:

> "Jurisdictional regulatory practices promise to be a key element in determining the ultimate impact on issuer creditworthiness given the sharp increase in the cost of capital as a result of the ongoing financial crisis. Utilities in states that have authorized reasonable returns on equity and adopted balanced regulatory mechanisms, including forward test years and automatic fuel and other tariff adjustment mechanisms are more likely to come through this period of stress without undue deterioration to current creditworthiness."

Fitch further emphasized this position in their December 2008 report titled "U.S. Utilities, Power and Gas 2009 Outlook" (Exhibit No. ___ (TRS-14) to my rebuttal testimony), stating:

> "Average authorized returns on equity (ROE) for the regulated utility sector are currently in the 10.25% to 10.5% range, with some jurisdictions approaching 9%. Fitch is concerned that absent a meaningful up-tick in authorized ROE, the industry may have difficulty attracting adequate capital to fund new reliability, infrastructure and renewable energy projects in light of the significant change in capital market conditions and investor expectations...[The] ratings of utilities operating in states with relatively low authorized ROEs and significant regulatory lag are more likely to suffer credit deterioration."

While each rating agency uses a different methodology, they would all view the adoption of Dr. Woolridge's recommended ROE as very unsupportive to the overall financial health of PEF and would likely result in a rating downgrade.

III. Importance of Cash Flow to PEF's Financial Health.

Q. Mr. Lawton identifies the net impact from his adjustment to the depreciation reserve as a reduction of the Company's pre-tax cash flow of about $149 million per year for four years. He maintains that PEF will maintain its "financial integrity" after correcting for the excess depreciation reserve. Do you agree with his assertion?

A. No, I do not. Mr. Lawton clearly states that his adjustment will result in lower cash from operations for the Company, a key component of the credit rating evaluation process. Cash flow is emphasized by S&P in their January 2009 report titled "Top 10 Investor Questions For The U.S. Electric Utilities Sector In 2009" (Exhibit No. ___(TRS-17) to my rebuttal testimony), where they state that "[those] companies that fare poorly in the regulatory arena and experience significant deterioration in cash flow metrics and creeping debt leverage are most vulnerable to downward actions." Mr. Lawton then goes on to state that "the Company's cash flow ratios decline slightly, but remain well above industry averages," and that PEF "maintains financial integrity after correcting for the excess depreciation." (Lawton Test., p. 19).

I have several concerns with Mr. Lawton's conclusions. First, Mr. Lawton references the financial ratio medians by bond rating category in his Exhibit DJL-5, p. 2 of 2. Since no source is provided for this data, I cannot be sure if the financial

ratios are provided on an unadjusted basis, or if they include adjustments made by the credit rating agencies. In any event, a comparison to industry medians is not the best comparison, as the rating agencies give specific guidance and target metric ranges that will more directly determine PEF's credit rating.

Mr. Lawton then references the ratios calculated in Exhibit DJL-5, p. 1 of 2, as evidence of PEF maintaining financial integrity after correcting for the excess depreciation. I have several issues with the ratios he calculates in this exhibit. First, the ratios are calculated based on the capital structure supplied by the Company on MFR Schedule D-1a, p. 1 of 3. This capital structure is the jurisdictional capital structure used for ratemaking purposes. The credit rating agencies calculate their metrics starting with the book capital structure for the entire company. Second, he includes only long-term debt in the metrics, while the rating agencies look at total debt (long-term and short-term). Third, the calculations are not made using the methodology or adjustments of the credit rating agencies for items such as capital leases, operating leases, PPAs, and pension liabilities. As such, the metrics are not comparable to the target ranges shown in his column C. Finally, Mr. Lawton states that financial ratios such as "debt ratio" are unaffected by the correction of the excess reserve. This is not possible, as his recommended correction to the excess reserve would result in lower cash from operations and thus higher financing needs. Finally, the interest expense of $189 million used in Mr. Lawton's calculation is grossly understated. S&P used adjusted interest expense of $295.7 million in its PEF credit metric calculations for 2008, and interest expense will be higher in 2010.

In addition to these calculation errors, Mr. Lawton states on page 20 that his "analysis focuses solely on the excess depreciation reserve impact and demonstrates that the cash flow reduction allows Progress to maintain solid financial metrics." This analysis is incorrect, as one must look at the *total of all the adjustments* proposed by the intervenors and those adjustments' impact on cash flow metrics, not individual adjustments in isolation. In short, neither the metric calculations nor comparisons referenced by Mr. Lawton allow any conclusions to be drawn regarding the financial integrity of PEF.

Q. The testimony of Mr. Schultz indicates that rates should be reduced by at least $35.038 million. This rate reduction, as calculated on Schedule A-1 of his testimony, uses the capital structure, return on equity and cost of debt recommended by Dr. Woolridge. Does Mr. Lawton capture all of the consequences the adoption of the proposed rate reduction would bring about?

A. No, he does not. His calculations incorrectly assume that there would be no negative consequences to the cost of capital for the Company if the rate decrease were adopted. As discussed above, Moody's specifically focuses on four key rating factors that are central to the assignment of ratings for utilities in their credit assessment process: (1) regulatory framework; (2) ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. The process is outlined in the Moody's report "Rating Methodology: Regulated Electric and Gas Utilities" issued in August 2009 (Exhibit No. __(TRS-15) to my rebuttal

testimony). The primary financial metrics utilized by Moody's, along with guidelines for an "A" rating, are as follows:

Financial Metric	Guidelines for "A" Rating
(CFO[1] pre-WC[2] + Interest) / Interest	4.5x – 6.0x
CFO pre-WC / Debt	22% – 30%
(CFO pre-WC – Dividends) / Debt	17% – 25%
Debt / Capitalization	35% – 45%

[1] CFO = Cash from Operations

[2] WC = Working Capital

The credit metric guidelines for our target credit rating reflect all of the standard adjustments normally incorporated by Moody's when analyzing financial statements.

In their June 2009 credit opinion for PEF, Moody's said the following regarding what could cause a credit rating downgrade for PEF:

> "A downgrade could be considered if there is an adverse change in the regulatory environment in Florida which could limit full and timely recovery of costs, especially the cost of new nuclear generation; a continued increase in leverage; new, unanticipated capital expenditure requirements; if financial metrics do not recover from 2008 levels and CFO before working capital plus interest to interest remains below 4.0x; and CFO before working capital to debt remains below 20% for a sustained period."

See Exhibit No. __ (TRS-18) to my rebuttal testimony. Exhibit No. __ (TRS-19) to my rebuttal testimony shows the key 2010 cash flow credit metrics for PEF calculated

using both S&P's and Moody's methodologies. The metrics are provided based on PEF's proposed rate increase and Mr. Schultz's proposed rate decrease. The calculations clearly show that PEF does not meet the standards specifically set forth by Moody's in their credit opinion for the Company if Mr. Schultz's recommendations were adopted. Thus, my conclusion is that PEF's credit rating would likely be downgraded. The metrics based on PEF's proposed rate increase are in line with the ranges for an A rating. As discussed above, no intervenor questioned the importance of PEF strengthening its financial profile or achieving a consistent target credit rating of mid-single A, and yet their recommendations would likely result in a credit rating downgrade. This would result in a higher cost of capital, which would ultimately increase rates for customers.

The importance of a strong credit rating was summarized by Steve Fetter, president of Regulation Un-Fettered, former chairman of the Michigan PSC, and former head of the global power group at Fitch Ratings in his May/June 2009 article titled "The A Rating" (Exhibit No. __ (TRS-20) to my rebuttal testimony):

> "Perhaps we have returned to a time when it would be in the interest of both companies and regulators to work in concert to support credit profiles for regulated electric utilities (optimally in the A category), for the good of both consumers and investors...The bottom line is that electric utilities must collect sufficient cash flow through rates to maintain strong credit ratings. This is especially true for companies needing to proceed with major generation construction, notwithstanding the negative economic environment. S&P has highlighted cash flow as the single most critical aspect of all credit rating

decisions. And liquidity is the lifeblood of day-to-day utility management flexibility."

The intervenors' rate reduction proposal would accomplish just the opposite: reduced cash flows, weaker credit ratings, and a weaker balance sheet; all during one of the strictest capital markets and at a time when the Company is embarking upon one of the largest capital programs in its history and needs access to the lowest possible cost of capital.

Q. Do you believe the overall recommendation of the $35 million rate decrease, which includes the adoption of Dr. Woolridge's recommended ROE, could impact PEF's plans to construct new nuclear plants?

A. Yes, I do. In their June 2009 report titled "New Nuclear Generation: Ratings Pressure Increasing," Moody's states the following:

"From a credit perspective, companies that pursue new nuclear generation will take on a higher business and operating risk profile, pressuring credit ratings over the intermediate- to long-term. Even so, we also believe companies will ultimately revise their corporate-finance policies to begin materially strengthening balance sheets and bolstering available liquidity capacity at the start of the construction cycle.....In general, we believe a company should prepare for the higher risk associated with construction by maintaining, if not strengthening, its balance sheet, and by maintaining robust levels of liquidity capacity."

See Exhibit No. __ (TRS-21) to my rebuttal testimony. Clearly, the recommendation of a $35 million rate reduction does not help PEF strengthen its financial position. Given that the rating agencies and the financial community require sound financial management and a strong financial position before entering the construction cycle for new nuclear plants, our plans could certainly be in jeopardy if the recommendation is adopted.

IV. Capital Structure.

Q. Dr. Woolridge asserts that the Company's capital structure with a common equity ratio of 53.9% is high relative to (1) the Company's actual historic capital structure and (2) the capital structures of other electric utilities (page 5). Do you agree with these assertions?

A. No, I do not. Dr. Woolridge's comparisons are not correct, as he is comparing an adjusted equity ratio to book equity ratios. In addition, PEF's 2008 book equity ratio was low due to timing differences associated with fuel cost recovery and fuel hedging, leading to higher debt at PEF before those costs are recovered from customers. In the comparison to the capital structure of other utilities, Dr. Woolridge chose a peer group of other electric utilities that represents both operating companies and parent companies, leading to unfair comparisons. The June 2009 Fitch report entitled "U.S. Electric and Gas Financial Peer Study" stated that "the business risk profiles of utility parent companies remain widely disparate, which often accounts for the rating discrepancy among companies with similar ratios" (Exhibit No. ____

(TRS-22) to my rebuttal testimony). Neither comparison made by Dr. Woolridge supports his assertion that PEF's requested capital structure is high.

Q. On page 18 of his direct testimony, Dr. Woolridge references the capitalization ratios for Progress Energy over the past three years and states that "these ratios also show that Progress Energy finances its other businesses and operations with more debt than PEF." Do you agree with this conclusion?

A. No, I do not. Progress Energy has divested of all of its material non-regulated operations, leaving Progress Energy Carolinas (PEC) and Progress Energy, Inc. (the holding company) as the key remaining entities other than PEF. PEC ended 2008 with a book common equity ratio (GAAP) of over 54% and has thus been funded with less debt than PEF. As described above, the primary reason for Progress Energy's common equity ratio being lower than PEF's is the debt at the parent (Progress Energy, Inc.) that remains from the acquisition of Florida Progress Corporation.

Q. Do you agree with Dr. Woolridge's recommended capital structure, with a common equity ratio of 50%?

A. No, I do not. PEF's credit ratings are determined based a capital structure with imputed debt, which Dr. Woolridge ignores. A strong balance sheet is critical for PEF. S&P stated the importance of balance sheet strength in its January 2009 report "Credit FAQ: Top 10 Investor Questions For The U.S. Electric Utility Sector in 2009," saying:

"The electric utility industry is asset-intensive and relies heavily on debt. Balance-sheet strength is a distinguishing factor when Standard & Poor's assesses financial risk and determines credit quality. Our analysis attempts to portray the economic reality of the financial conditions and considers several items, including purchase power obligations, capital leases, hybrid equity instruments, pension liabilities, and regulatory assets."

See Exhibit No. __(TRS-17) to my rebuttal testimony. As this quote demonstrates, looking at PEF's capital structure on an adjusted basis is critical.

To correct one point, on page 21 of his testimony, Dr. Woolridge states that PEF's "real" recommended common equity ratio, on a jurisdictional basis, is 47.51% based on investor provided capital. His calculation of this "real" recommended common equity ratio does not properly account for the 75.95% jurisdictional factor of the equity adjustment for PPAs. The correct ratio should be 49.2% on a jurisdictional basis, not 47.51%.

Q. Do you agree with Mr. Pollack's assertion that a 50% common equity ratio is sufficient to maintain PEF's current bond rating?

A. No, I do not. In order to determine the impact on PEF's bond rating, the adjustments made by the credit rating agencies (such as imputed debt for PPAs) are a financial reality for PEF and must be considered. In addition, a number of factors are used to determine PEF's credit rating, not just its capital structure. As described above, all of the intervenors' recommendations should be considered together to determine the impact on PEF's credit rating. In this case, the recommendations do not allow PEF to

maintain sufficient credit metrics to support its current rating and would likely result in a credit rating downgrade.

V. Financial Impact of PPAs.

Q. How do the rating agencies treat long-term power supply contracts and what is the impact of their treatment of the PPAs on the Company?

A. As I explained in my direct testimony, while there are differences in methods, each rating agency views PPAs, with their long-term obligations, as essentially debt-like in nature. The main effect of the impact of this treatment of PPAs on PEF's financial structure is that the Company is considered to have more leverage than if you calculated its leverage ratio based only on the debt recorded on its balance sheet.

Q. Dr. Woolridge identified S&P's lack of guidance on the risk factor (page 60) as a flaw in the PPA equity adjustment. Similarly, Mr. Pollack states that S&P does not provide an objective standard for determining the appropriate risk factor for PPAs. Should there be any question regarding the risk factor S&P applies to PEF's PPAs?

A. No, there should be no question regarding the risk factor S&P applies to PEF's PPAs. In their November 2006 article entitled "Request For Comments: Imputing Debt To Purchased Power Obligations" (Exhibit No. ___ (TRS-23) to my rebuttal testimony), S&P states the following:

> "In those instances where recovery of PPA-related capacity costs is guaranteed by a legislative mechanism, the level of the risk factor will be

determined by the timeliness provided by the legislative true-up mechanism. The strength of the mechanism can result in risk factors as low as 0% because legislatively prescribed recovery mechanisms are viewed as providing utilities with a greater level of protection than that provided by regulatory orders."

PEF's recovery of PPAs is not prescribed by legislation. Therefore, S&P does not use a 0% risk factor when imputing debt for PEF's PPAs. S&P's report goes on to say:

"To date, where PPA capacity costs were recovered through a fuel adjustment clause (FAC), as compared with base rate recovery, a risk factor of 30% has generally been used...Based on the effectiveness of FAC mechanisms, we will adjust modestly the risk factor of 30% down to 25%."

Based on our discussions with S&P, a 25% risk factor is used for PEF's PPA adjustment.

Table 3 on Page 6 of the S&P credit opinion for PEF dated June 15, 2009 shows that PEF's book debt for 2008 was increased by $696.3 million for PPAs. See Exhibit No. __ (TRS-24) to my rebuttal testimony. Similarly, for 2007, S&P made a debt adjustment of $780.3 million for PPAs. See Exhibit No. __ (TRS-25) to my rebuttal testimony. The 2007 and 2008 adjustments are in line with the $711 million adjustment shown by the Company for 2010. Dr. Woolridge and Mr. Pollack reference general guidance published by S&P, but it cannot be disputed that S&P makes a significant debt adjustment at PEF for PPAs.

Q. Dr. Woolridge also points out that S&P's adjustments for PPAs are not GAAP accounting, and that PPA payments are unlike debt from a regulatory perspective (page 61). Do you agree with these points, and should they impact the imputed equity adjustment you have requested?

A. While I agree that S&P's adjustments for PPAs are not GAAP accounting, I do not agree that this impacts the Company's request for the imputed equity adjustment. The treatment of PPAs as debt by the rating agencies has a material impact on PEF's credit profile and potentially its cost of capital. For 2008, S&P increased PEF's book debt by $696.3 million and interest expense by $40.0 million for the effect of PPAs. The effect of off-balance sheet obligations like PPAs on a utility's capital structure has also been recognized by the Florida Public Service Commission, as outlined on pages 20 and 21 of my direct testimony. The points raised by Dr. Woolridge should have no impact on the imputed equity adjustment.

Q. Mr. Pollack states that "it seems unlikely that the debt [associated with PPAs] will be imputed [by Moody's] to PEF based on the cost recovery mechanisms applicable to purchased power capacity costs." Is this true?

A. No, this is not true. While Moody's does not make an explicit adjustment for PPAs like S&P, they do make adjustments for capital and operating leases. Many PPAs are classified as capital or operating leases under GAAP. Thus, Moody's does impute debt for PEF's PPAs that are classified as capital or operating leases. For example, in 2008 Moody's did not make a direct PPA adjustment, but did adjust 2008 book debt by $245 million for operating leases. Likewise, S&P made an operating lease

adjustment of $28.7 million for PEF in 2008. This was in addition to the $696.3 million adjustment for PPAs. The higher operating lease adjustment by Moody's compared to S&P was driven by PPAs treated as operating leases by the Company. The operating lease adjustment by S&P specifically excludes PPAs treated as operating leases, as the debt is imputed through the PPA adjustment. Thus, both rating agencies adjusted PEF's book debt for PPAs, although their methodologies are different.

Q. Do you agree that the PPA adjustment should be removed?

A. No, I do not. All three rating agencies consider off-balance sheet obligations when assessing a company's credit quality. While each has different methodologies for the treatment of PPAs, each rating agency looks at PPAs when assessing PEF's credit quality. It is important for PEF to obtain a consistent target credit rating from all three rating agencies. As such, we focus on the most restrictive methodology for PPA treatment, which is S&P's.

VI. Cost of Debt.

Q. Has your view in interest rates changed since you prepared the forecast supporting PEF's rate request?

A. The financial markets and interest rates continue to be extremely volatile. While government intervention has led to recent historically low rates, the general consensus is that the cost of capital will increase in the future. S&P stated in its January 2009 report "Credit FAQ: Top 10 Investor Questions For The U.S. Electric Utility Sector

In 2009," that "regulators' willingness to recognize the higher cost of capital through overall returns is important for credit quality." See Exhibit No. __ (TRS-17) to my rebuttal testimony.

Our methodology for forecasting interest rates is based on observing market forward curves for LIBOR and U.S. Treasuries and expected credit spreads. While the mix of these elements has changed over the past year, we believe that the rates included in our rate request are still reasonable for 2010.

Q. Do you agree with Dr. Woolridge's recommended short-term debt cost rate of 3.06%?

A. No, I do not. Dr. Woolridge bases his short-term debt cost rate on spreads above the average three-month LIBOR rate for 2009 of 1.0%. Although this average is more than double the current three-month LIBOR rate, it does not properly capture future expectations for increases in three-month LIBOR. As shown in Exhibit No. __(TRS-26) to my rebuttal testimony, three-month LIBOR is expected to be approximately 1.25% by the middle of 2010 and over 2.0% in December of 2010.

In addition, Dr. Woolridge's recommended short-term debt cost rate of 3.06% includes 0.21% for fees associated with the Company's credit facility. These fees are fixed for 2010 as long as PEF's senior unsecured credit rating is not downgraded. The 0.21% fee used by Dr. Woolridge is incorrectly based on 2009 amounts, as reflected on page 2 of MFR Schedule D-2. For the 2010 test year, the correct fee adjustment is 0.75%, as reflected on page 1 of MFR Schedule D-2. Thus, Dr. Woolridge's recommended short-term debt cost rate is understated by 0.54% for the

credit facility cost, as well as the understatement based on market expectations for increases in three-month LIBOR in 2010.

Q. Do you agree with Dr. Woolridge's recommended long-term debt cost rate of 6.05%?

A. No, I do not. The relevant long-term debt cost rate for this discussion is the long-term debt cost rate for 2010, the test year. Dr. Woolridge has chosen to use the overall embedded long-term debt cost rate for 2009 as the long-term debt cost rate for 2010, which does not properly reflect the long-term debt activity that will take place in 2010. PEF currently has a $300 million first mortgage bond outstanding with an interest rate of 4.50% that matures on June 1, 2010. In order for the 2010 long-term debt cost rate to remain at the 2009 embedded level of 6.05%, the $750 million new bond required in 2010 would have to be issued at a rate of 4.30%, assuming all other assumptions are held constant. This rate is well below the current yields Dr. Woolridge references for 10-year, A and BBB+ rated utility bonds of 5.19% and 5.60%, respectively (page 24).

In addition, Dr. Woolridge states that "a projected yield of 6.98% [PEF's assumed rate on the new $750 million bond on page 1 of MFR Schedule D-4a] is not reflective of current market interest rates" (page 24). PEF's projected yield is a reflection of expected *future* market interest rates, not current interest rates. His statement does not consider the fact that the yields on ten-year and thirty-year U.S. Treasury notes/bonds are expected to increase in the future, to well over 4.0% and

5.0%, respectively, in 2010. Please see Exhibit No. __(TRS-26) to my rebuttal testimony.

In addition, PEF has historically issued a mix of 10- and 30-year bonds. The assumed interest rate for the new 2010 issuance was intended to reflect the potential for a blend of 10-year notes and 30-year bonds. The 30-year bond would have a higher interest rate than the 10-year bond. Using only today's 10-year rates as a proxy for rates in the future leads to unrealistically low new debt issuance cost assumptions for 2010.

Q. Have you addressed the principle arguments raised by the intervenors that challenge the Company's proposed capital structure and the impact of their recommended return on equity and cost of debt on the Company's financial health?

A. Yes, I believe that I have. To the extent that I have not addressed some further argument to the contrary, however, the Company does not agree with it but rejects it for all the reasons that I have provided in my direct and rebuttal testimony.

Q. In conclusion, could you please summarize your conclusions regarding the impact of the intervenors' recommendations on the Company's financial health and credit rating?

A. As I stated in my original direct testimony, it is important for PEF to strengthen its credit profile and achieve a consistent target credit rating of mid-single A. No intervenor witness disputed these positions. Their recommendations regarding the

cost of capital and capital structure, however, would not allow PEF to achieve these goals. If their recommendations were adopted, the change in the tone of the Florida regulatory environment and the resulting implications on the Company's cash flow and credit metrics would likely result in a credit rating downgrade, which in turn would jeopardize the Company's ability to serve its customers effectively and would ultimately result in higher rates.

Q. Does this conclude your testimony?

A. Yes, it does.

www.moodys.com

Industry Outlook

Moody's Global
Infrastructure

January 2009

Table of Contents:

Analyst Contacts:

New York	**1.212.553.1653**
Jim Hempstead	1.212.553.4318
Senior Vice President	
W. Larry Hess	1.212.553.3837
Team Managing Director	

(Analyst contacts continued on page 14)

U.S. Investor-Owned Electric Utilities

The outlook for the U.S. investor-owned electric utility sector is stable. This outlook expresses Moody's expectations for the fundamental credit conditions in the industry over the next 12 to 18 months.

- Fundamentals expected to remain intact near-term, but concerns over rising business and operating risks may stress credit profile longer term.
- State regulators continue to grant timely recovery of prudently incurred operating costs and capital expenditures with a reasonable rate of return.
- Key financial credit metrics likely to deteriorate modestly over next 12 to 18 months – not a big concern today. Companies have adequate time to begin financial strengthening program to fortify position within given rating category.
- Key challenges that need to be addressed include:
  - **Potential for significant environmental legislation,** including carbon emissions, represents a material "wild card" due to uncertain costs, framework and implementation timeframe.
  - **Sizeable infrastructure investment plans** include all facets of the traditional, vertically-integrated rate base. Deferrals and delays are temporary solutions.
  - **Regulatory overhang** concerns over the pace and amount of financial relief could agitate consumer tolerance to absorb steadily increasing rates, especially in a protracted/severe recession.
  - **Protracted economic pressures** may increase intensity of business and operating risks.
- Near-term liquidity profiles appear adequate at this time, but maintaining unfettered access to capital markets will be critical.
- Credit facility expirations loom, posing a significant and material concern if markets do not improve.
  - **Major financial institutions exiting commodity markets** represent an intermediate-term risk, as contract expirations occur amid higher capital costs and managing hedging activity becomes more challenging.
- Issuers' different approaches to future uncertainties will be set by "tone at the top" — missed opportunities to issue equity over last several years may prove to be unexpectedly costly for some.

Moody's Investors Service

U.S. Investor-Owned Electric Utilities

Overview

The U.S. investor-owned electric utility sector enjoys solid credit metrics and the fundamental credit outlook remains stable. In general, state regulators continue to let the utilities recover prudently incurred operating costs and capital expenditures relatively quickly, and with reasonable rates of return. Moreover, we believe state regulators would otherwise prefer to regulate financially healthy companies.

The sector is also well positioned relative to many other corporate/industrial sectors, primarily due to the fundamental business plan: providing monopolistic electric service within a designated service territory in exchange for oversight and limitations on profitability. However, we are increasingly concerned with business and operating risks, which are not new but appear to be accelerating faster than previously understood. These business and operating risks include potential environmental legislation from the Obama Administration; the continued capital investment needs for refurbishing aging infrastructure; and a potentially more contentious regulatory relationship amid a protracted or severe recession.

Although liquidity appears to be reasonable today, the sector's substantial negative free cash flow generation creates a need for unfettered access to the capital markets. This represents a fundamental weakness to the sector's business plan.

Our concerns are clearly growing, but we believe utilities have adequate time to adjust and revise their corporate finance policies and strengthen balance sheets, thereby improving their ability to manage volatility and address uncertainty. Individual issuers can strengthen their balance sheets through various means, but we continue to believe that the most effective and efficient method is a large infusion of new common equity. To date, we have seen only a modest amount of proactive new equity issuances, but the industry has begun showing a noticeable openness toward issuing new equity.

Table 1: Selected industry sector comparison[1]

	CFO/Debt			RCF/Debt			Debt/EBITDA		
Sector Averages	2007	LTM 3Q08	5-year average (2003-2007)	2007	LTM 3Q08	5-year average (2003-2007)	2007	LTM 3Q08	5-year average (2003-2007)
US Investor Owned Utility (IOU) Holding Companies	17%	15%	17%	14%	14%	14%	4.1	4.2	4.3
US IOU Integrated Utilities	22%	20%	23%	17%	18%	17%	3.4	3.7	3.4
US IOU T&D Utilities	15%	19%	18%	13%	15%	14%	3.6	3.8	3.8
North American Gas Distribution	18%	17%	17%	14%	13%	15%	3.8	3.2	4.0
North American Gas Diversified	23%	22%	20%	17%	19%	16%	3.7	3.7	3.6
North American Gas Pipelines	22%	17%	23%	16%	10%	16%	4.6	3.1	3.6
Oil/Gas Independent Exploration & Production	87%	86%	366%	76%	81%	240%	nm	nm	11.6
Oil/Gas Integrated	90%	94%	81%	75%	70%	69%	0.9	0.8	1.2
Global Coal	27%	34%	30%	23%	30%	27%	5.7	7.3	3.8

Source: Moody's Financial Metrics.

[1] The individual companies that comprise the industry sector peers groups can be found in their respective Rating Methodology reports.

Key Trends and Rating Implications

Sector well-positioned to cope with recessionary pressures

Electric utilities, like many infrastructure-based businesses, are considered resistant (though not immune) to the current economic and financial market conditions, and the risks of a protracted or severe recession. From a credit perspective, electric utilities are better positioned than many other corporate/industrial sectors. Utilities produce relatively stable and predictable revenues, earnings and cash flows, which are not expected to decline significantly despite recessionary pressures. The sector is capitalized at roughly 55% debt and 45% equity. Near-term liquidity profiles appear adequate at this time and the option of raising external capital remains viable, albeit at higher costs.

Table 2: Top 10 Negative Sectors Globally (as of third quarter 2008)

Industry	Negative Outlook and Rating Under Review for Possible Downgrade Third-Quarter 2008	Negative Outlook and Rating Under Review for Possible Downgrade Fourth-Quarter 2007
Airlines	65%	8%
House building	58%	40%
Newspapers	57%	24%
Restaurants	53%	29%
Gaming	46%	20%
Building Materials	45%	25%
Apparel	43%	23%
Trucking	41%	27%
Consumer Durables	41%	31%
Automobiles	38%	11%

Modest declines expected in key credit metrics not alarming . . . yet

Over the past few years, the sector produced relatively steady key financial credit metrics, a credit positive. Prospectively, we expect these metrics to decline modestly given the increasing operating costs, infrastructure investment needs, plans to finance negative free cash flows primarily with debt, and emerging concerns that poor economic conditions may hinder regulatory relief.

Nevertheless, the likelihood that the sector might drop below the investment grade rating category appears remote at this time, although downgrades within the broader investment grade rating categories are possible. Even under several downside scenarios, the projected ratio of cash flow from operations (CFO) to total adjusted debt should remain in the mid- to high-teens range (down from approximately 20%) and the ratio of debt to capitalization might rise to roughly 55% to 60% (up from 52%), as seen a few years ago.

Projections demonstrate resiliency of utility business plans

We reviewed the average historical financial statements for about 55 vertically-integrated electric utility companies, analyzing the period from 2002 through the 12 months ended September 2008. We used the resulting average financials to create OpCo—a hypothetical, vertically-integrated electric utility. We then applied numerous assumptions to OpCo to make illustrative financial projections for 2009 through 2013. The projections begin with the actual, as adjusted, financials reported for the 12 months ended September 2008, and reflect Moody's standardized GAAP adjustments.[2]

[2] Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations – Part I (July 2006).

U.S. Investor-Owned Electric Utilities

We begin our demonstration with an assumption that the global economy is entering a protracted period of "healing" with a focus on decreasing leverage. This translates into a slow economic recovery, perhaps sometime in 2010.[3] We project that the sector's volumes will decline by 3% in 2009, remain flat in 2010 and then increase by 1% in 2011 and 2012 and 2% in 2013.

We assume annual rate increases of 5% over the next five years. We also assume 5% annual increases in operating and maintenance (O&M) expenses as well as fuel, purchased power and all tracker expenses. Our model uses a dividend policy of 65% of prior year's net income and assumes that negative free cash flows are financed 80% with debt (at an 8% coupon) and 20% new equity (incremental to any retained earnings).

For our analysis, OpCo's CFO averages 18% of its revenues in 2009 and 2010 and 17% thereafter – a decline that reflects historical trends[4]. We also set OpCo's capital expenditures at 200% of prior year's depreciation expense in 2009; 175% in 2010; 200% in 2011; 225% in 2012; and 250% in 2013.

Table 3: Summary of illustrative projection scenarios

					2013 Projected		
Scenario	Dividend Payout	Negative FCF Debt Financing	Fuel, Purchased Power & Trackers	Annual Rate Increases	Rates (cents/kWh)	CFO/Debt	ROE
Base Case	65%	80%	5%	5%/year	12.2	17%	8.9%
Base A	65%	80%	5%	10% ROE target	12.5	17%	10.0%
Wild B	65%	80%	10%	5%/year	12.2	18%	(0.4%)
Wild C	65%	80%	10%	10% ROE target	13.9	20%	10.0%
Mitigant D	0%	100%	10%	7%/year	13.4	20%	6.7%

Under the Base Case scenario, OpCo maintains relatively steady financial credit metrics, where cash flow from operations (CFO) as a percentage of total debt declines modestly from 20% in 2008 to 17% in 2013; CFO interest coverage declines from 4.7x in 2008 to 3.7x in 2013, and; debt to capitalization increases from 52% in 2008 to 55% in 2013. Gross margins and EBITDA margins remain relatively steady at approximately 50% and 30%, respectively and rates increase from 9.6 cents per kWh to 12.2 cents in 2013. The issue, as we see it, is the ROE (net income/equity) falls to roughly 7% over the next few years before improving to almost 9% by 2013.

Our Base A scenario keeps all of these assumptions except that it factors an annual rate increase necessary to achieve an annual 10% ROE. Again, the resulting financial profile is not overly alarming from a credit perspective, as the ratio of CFO to debt still falls modestly to 17% and the CFO interest coverage ratio falls to 3.7x. The ratio of debt to capitalization increases to almost 54%, not a material increase, while total rates per kWh increase modestly to 12.5 cents (versus 12.2 cents per kWh in the Base Case). We observe that the Base A scenario requires larger rate increases in the front years (9% in 2009 versus 5% in the Base Case) and lower increases in the later years (3% versus 5% in the Base Case).

Several wild cards are floating in the deck

One of our "wild card" scenarios (Wild B) differs from the Base Case in one respect: it assumes OpCo sees annual 10% rises in fuel, purchased power and tracker expenses, rather than 5% increases. While the key financial credit metrics would not decline meaningfully in this scenario as compared to the Base Case[5], the ROE would fall almost to zero by 2012, and would be negative in 2013—a material issue associated with both our assumptions and the mechanics of our model.

[3] Moody's Global Financial Risk Perspectives (December 2008).
[4] CFO is comprised of net income and depreciation (calculated by the forecast model) and "other" – which includes deferred taxes and is a plug between CFO, net income and depreciation.
[5] I.e., CFO/debt falls to 17% and CFO interest coverage falls to 4x.

Our Wild C scenario is set to produce rate increases that give OpCo an annual ROE of 10% (all other assumptions remaining the same as in the Wild B scenario). Wild C scenario requires significantly higher rate increases than the Base Case's 5% per year annual rise: an 11.6% increase in 2009; 7.6% in 2010; 6.8% in 2011; 7.1% in 2012 and 6.3% in 2013. From a credit perspective, we would question the likelihood of success in achieving these levels of rate increases, especially given current economic conditions.

In the Mitigant D scenario, we continue to assume the 10% annual increase in fuel, purchased power and tracker expenses of the "Wild" scenarios. We further assume that OpCo maintains a steady capital investment policy of 225% of prior years D&A (no delays/no reductions) because of a greater recovery assurance from regulators, resulting in a 7% annual rate increase, every year, over the next five years (instead of 5% per year). In addition, OpCo eliminates its common stock dividend and finances its negative free cash flow with 100% debt.

Under Mitigant D, OpCo maintains relatively robust financial metrics: CFO debt remains above 20%; CFO interest coverage declines to 4.3x; and debt to capitalization stays at 52%. Importantly, ROE's fall to the 7% range – perhaps a reflection of a lower risk profile given the authorized recovery assurances by regulators.

For charts illustrating these five paths and how they affect OpCo's 2009-2013 financials, see Appendix A (page 10).

Rate recovery: Regulators have the last word

We continue to incorporate a view that individual state regulatory authorities will provide reasonably timely recovery of prudently incurred costs and investments. Moreover, we continue to believe that regulators prefer to otherwise regulate financially healthy companies. This relationship often creates a virtuous cycle, where financially healthy utilities have the balance sheet strength and liquidity to assure investment, maintain high levels of reliability and attract economic development. In turn, this tends to facilitate contentment among consumers, legislators and regulators.

Regulation is political by definition. In a protracted economic downturn, we may see regulators or legislators attempt to shield consumers from rate increases more aggressively—possibly through recovery deferrals or some form of new market structure intervention. For example, we believe bad debt expense will increase significantly over the next 12 to 18 months, highlighting the need to maintain adequate amounts of liquidity to manage this risk and potentially testing the regulatory timing mechanisms associated with recovery.

Regulatory lag can (and often will) develop, especially when a utility's cash outflows are materially outpacing its authorized revenue requirements (cash inflows). We remain cautious as to the potential "flaring" of regulatory risk on the sector and believe it is more likely to occur in states that had previously attempted some form of legislatively mandated market restructuring. In our opinion, it can take years before stress is fully resolved between a utility and its regulators/legislators.

Fundamentally, our primary concern is that as total revenue requirements rise, so does the risk of a consumer backlash that could prompt legislative intervention or a more contentious atmosphere between utilities and their regulators.

Riders may not be risk-free

We observe that the sector is moving deliberately towards a more transparent recovery format by introducing numerous cost "trackers" and/or other rate "riders" associated with environmental expenditures, storm recovery, efficiency programs and other renewable energy mandates.

Over the near-term, Moody's views rate riders/trackers as a credit positive. Riders assure up-front recovery and theoretically provide more transparency to the operating costs and margins (if any) associated with various social/legislative initiatives. In addition, riders provide a mechanism for utilities to enter into non-economic business decisions that address certain social mandates, and they appear to be more palatable for managing "headline" risk associated with rate increases (i.e., lots of small increases related to numerous riders are easier for consumers to absorb than the less frequent large base-rate increase). From a credit perspective,

because riders may lower the risk profile of a utility by better assuring near-term recovery, it is conceivable that higher leverage can be utilized without adversely impacting existing ratings.

However, it is unclear, at this time, as to whether these cost riders/trackers may prove to have hidden consequences over the long-term horizon. Riders may be viewed by some regulators as materially lowering the over-all risk profile of a utility, resulting in lower authorized returns on equity and/or rate base. They may also contribute to higher earnings volatility, may pressure future requests for base rate relief, or may lead to future disputes with regulatory authorities over the application or administration of the tracker mechanism.

"Wait and see" is a perilous stance

The new Obama Administration is likely to take a more active stance toward integrating energy and environmental policy than the Bush Administration. Already the Obama Administration's appointments to lead the Department of Energy and Environmental Protection Agency suggest that the electric utility sector may see changes more quickly than we had previously expected, and we are still evaluating how they will affect our ratings and rating outlooks. We also await the appointment of a new chairman for the Federal Energy Regulatory Commission. We expect to be in a position to clarify our views as details and policy agendas emerge.

We believe solid investment-grade utilities will not choose a "wait and see" strategy, but will instead pursue a long-term effort to bolster their balance sheets now and try and reduce the risk of future credit rating downgrades. While details of the new Administration's priorities and environmental legislation remain unknown today, we believe threats to credit quality could outweigh potential benefits and opportunities. Yet so far we see no evidence that utilities are aggressively revising their corporate finance policies accordingly.

The big whammy: Prospects for CO_2 emission legislation

The prospect for new environmental legislation—particularly concerning carbon dioxide—represents the biggest emerging issue for electric utilities, given the volume of carbon dioxide emissions and the unknown form and substance of potential CO_2 legislation.

Today we believe the costs associated with any new CO_2 emissions law would be recovered through rates, either through existing fuel-clause pass-through mechanisms or other incremental rate riders[6]. The framework behind such legislation is still being developed, and is subject to considerable political influence. Numerous advocacy groups (including electric utilities and environmentalists) will have a significant opportunity to influence the drafting of the administrative procedures associated with implementation.

New emission legislation poses a potential near-term credit negative. Although the costs are expected to ultimately be borne by end-use consumers, the potential for regulators to limit other base-rate relief may increase. At a minimum, uncertainty risk will increase before it is resolved.

Need to replace aging infrastructure persists

Despite the numerous recent announcements of capital expenditure reductions, the sector is expected to invest heavily in its rate base and infrastructure over the next several years. However, many of the most expensive projects are long term in nature.

Utilities continue to emphasize that their commitment to making these investments will depend on some form of advanced regulatory support or acknowledgement that the investments will be deemed necessary and prudent — all in an effort to mitigate (not eliminate) back end regulatory disallowance risk.

From a credit perspective, we view pre-approvals and other up-front regulatory support as a material credit positive. In addition, regulatory assurances associated with recovery positions a utility to withstand higher amounts of leverage (and lower key credit metrics) for a given rating category. Nevertheless, since maintaining reliability is a key concern with regulators, the need to invest will not go away.

[6] In many economic circles, this is known as a tax.

Impact of new nuclear generation capacity aspirations[7]

Over the next few years, several companies in the electric utility sector will seriously consider the construction of new nuclear generating capacity—a long-term commitment that could be very costly. The pursuit of new nuclear generation could put significant pressure on the sector's overall capital investment plans. Utilities that pursue these projects will most likely take on a higher business and operating risk profile.

Counterparties depart the commodity trading scene

We believe 2008 served as a wake up call to the industry and that many companies will be reassessing hedging programs and strategies. From a credit perspective, companies that are able to identify and manage commodity risks effectively through dynamic hedging programs generally produce more stable cash flows. Assuming they maintain adequate sources of liquidity, these companies are viewed more favorably than those that do not hedge.

As a result of recent developments in the broad financial sector, a number of large financial institutions have decided to exit the commodity trading markets. Over the past few years, these banks and financial institutions had acted as important market-makers, providing liquidity, capital and term products to utilities seeking to trade around their assets or hedge components of their electric generation volumes. Given the spate of recent counterparty exits, we believe that utilities will have fewer counterparties with which to trade; that bid-ask spreads will widen sharply; and that the terms required at the expiration of purchase power contracts may become more onerous than exist today. Although this scenario has not yet become a major problem for the sector, we believe that the challenges loom around the corner.

Increased pension obligations add to total outstanding debt

We reviewed the 2007 funded status[8] for numerous rated utilities and calculated the estimated under-funding for the projected year-end 2008. Based on our simplified analysis, we estimate that the utility sector will be about $40 billion short for meeting its pension obligations as of year-end 2008. As a result, the sector may be required to contribute about $6.5 billion to its pensions during 2009. This compares to 2007 total contributions, required and voluntary, of $2.7 billion.

From a credit perspective, Moody's treats under-funded pension obligations as a debt equivalent that will weaken near-term financial credit metrics. Still, recent federal legislation may help smooth the industry's cash-contribution obligations. On balance, we do not view the impact of the increased debt and pension contributions as a material credit event at this time.

See Appendix B (page 11) for more details of projected pension obligations, both for the industry and for selected large utilities.

Here comes differentiation—driven by tone at the top

Utility executives' and board members' views of corporate finance policies may be changing. Utilities often claim that protecting and maintaining an investment-grade credit rating is critical for maximizing long-term shareholder value. Yet with significant headwinds facing the utility sector, we have been somewhat perplexed that some companies remain reluctant to consider issuing new common equity—even amid historically unprecedented market valuation multiples.

The opportunity cost from declining to issue new equity at such high levels may prove unexpectedly steep. Prospectively, we believe utilities will finance their sizeable negative free cash flows with a more balanced mix of debt and equity.

[7] For more detailed discussions of new nuclear generation, see Moody's Related Research (Special Comments), page 13.
[8] Based on the 2007 annual reports.

2009 U.S. Public Power Electric Utility Sector Outlook

Economic pressures and climate policy may affect stable outlook

The credit outlook for the U.S. public power electric utility sector will remain stable in 2009. But recessionary pressures and the prospect for more aggressive environmental regulation related to climate change create uncertainty in the outlook. Moody's rates over $100 billion of revenue bond debt from U.S. municipal and government-owned utilities. The sector's credit quality will also remain under pressure from the unsettled credit markets; uncertainty about fuel-price volatility; and the increasing cost of new generation capacity.

Power supply decisions will also be more difficult, with possible increases in renewable energy mandates. Public power retail rates have been rising over the past two years. This has created additional political risk for some utilities that seek to recover higher costs through rate increases as economic pressures cut into demand.

A U.S. recession over the next year could reduce electricity demand. Such a reduction, if not managed well, could create rating pressures for public power electric utilities. Lower demand could weaken debt service coverage margins or liquidity if rates are not raised to compensate. This weakening of financial metrics could lead to rating downgrades. The weakening fiscal health of local governments may also lead utilities to increase general-fund transfers to support a municipality's general finances. Doing so could weaken a utility's balance sheet and bring negative rating pressure.

Despite these uncertainties and pressures, the public power sector's stable outlook rests on its largely monopolistic position as a provider of an essential service, combined with its ability to recover costs through a rate-setting process that is *not subject to regulation*. Additionally, public power utilities have shown good ability to withstand the recent turmoil in credit and fuel markets.

There have been no public power credit rating downgrades associated with the impact of the unsettled credit markets. These utilities have managed their operations well, maintained generally sound finances, and provided reliable service to customers. Strategic efforts to manage changes in environmental regulation have also been undertaken. Moody's expects that this business model and performance record should be reasonably maintained in 2009.

Conclusion

The underlying fundamentals for the U.S. investor-owned electric utility sector remain intact. We foresee no significant changes to regulatory support of authorized recovery mechanisms associated with costs and investment.

Even so, the sector today faces material issues, such as the need to replace and refurbish aging infrastructure; an aging labor force and a growing pension burden; and the potential for new CO_2 emission legislation. These challenges might have a significant impact on overall credit quality for the sector—especially if they materialize more quickly than we are now expecting.

We still believe the sector has ample time to revise, adjust and amend corporate finance policies and long-term corporate strategies ahead of changing market conditions. In our opinion, a differentiation may start to emerge based on the corporate finance policies by which utilities address these challenges—the "tone at the top."

The biggest near-term challenge facing the sector is the need to maintain adequate sources of liquidity. This risk will become more obvious if some fundamental changes hit the sector sooner than expected.

U.S. Investor-Owned Electric Utilities

Over the intermediate term, the biggest challenge will be management's ability to balance a utility's financing needs with its infrastructure investments. A balanced mix of debt, preferred stock and common equity appears a reasonable strategy for companies within a solid, investment-grade sector with over a century of operating experience. Over time it also provides a better balance between the asset side of the balance sheet and the liability and equity side.

For the long term, the biggest risk could come from new environmental legislation. Although such new laws may be introduced sooner rather than later, it could take some time before the details of implementation are fully worked out. But given the sheer magnitude of the implications for the sector, we remain befuddled as to why utilities are not more aggressive with their balance-sheet strengthening programs.

All of these challenges and risks must be managed and addressed through the regulatory framework, which we still view as a fundamental credit positive. We foresee little long-term risk from mismanagement of the increasing social mandates between utilities and their constituents: customers, employees, investors, lenders, regulators and legislators.

Appendix A: Illustrative projections for OpCo, 2009-2013

OpCo, a hypothetical U.S. investor-owned electric utility, is a composite based on the financial results of about 55 companies (see "Projections demonstrate resiliency of utility business plans," page 3). These charts illustrate our projections of OpCo's 2009-2013 financials, using a base scenario and four others.

Chart A: CFO/Total Adjusted Debt

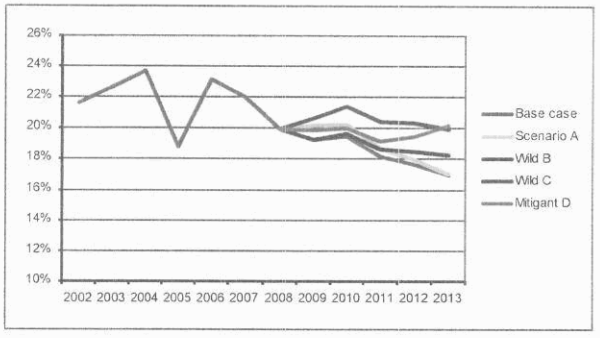


Chart B: Quality of CFO (NIATC+D&A/CFO)

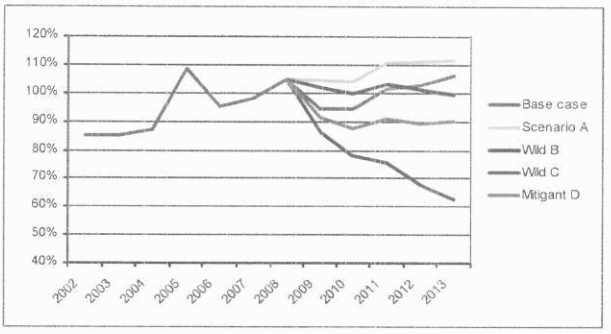


Chart C: Can ROE keep up?

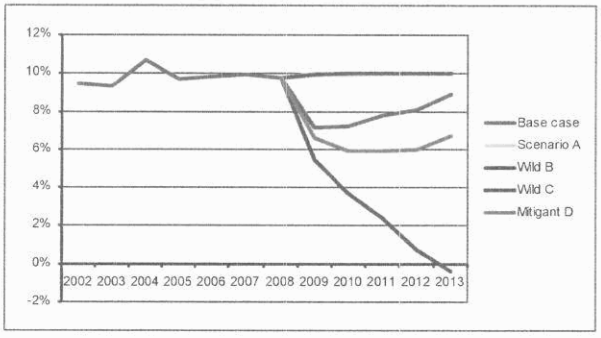


Chart D: Debt/Capitalization

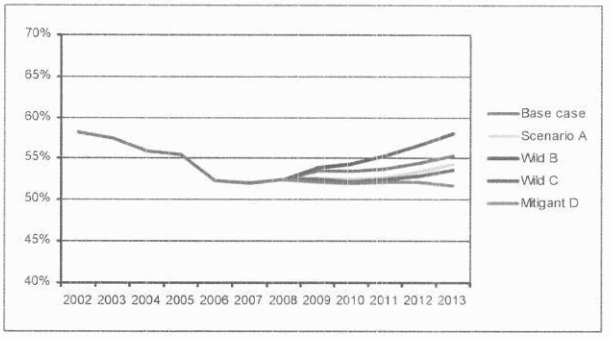


Chart E: CFO Interest Coverage

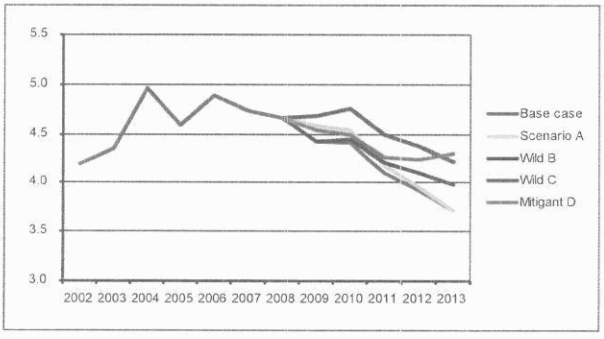
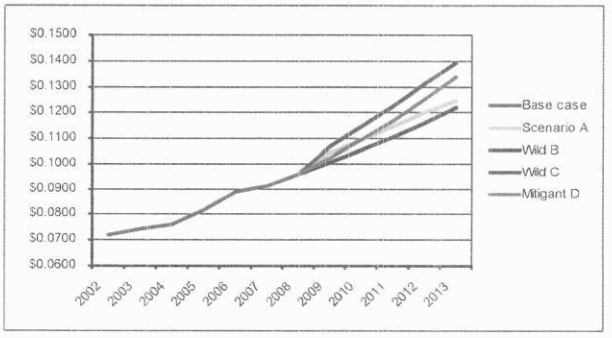


Chart F: (cents per kWh)



U.S. Investor-Owned Electric Utilities

Appendix B: Moody's estimated 2009 pension funding

In U.S. dollars (thousands) unless otherwise indicated. Public rated entities only

Summary projections	
Total underfunding ($), year ended 2008	(40,542,207)
Total underfunding (%), year ended 2008	69
Total 2009 contributions ($)	6,825,456

Assumptions	Equites	Fixed income	Other	Discount Rate
Asset Allocation	60%	30%	10%	N/A
Year to date losses	40%	10%	20%	N/A
Discount rate increase/(decrease)	N/A	N/A	N/A	-0.50%

Issuer name	2007 Reported Percentage Funded	Obligation	2008 Projected Over/(Under) Funding	Percentage Funded	2009 Projected Contributions
FPL Group, Inc.	217%	1,734,600	805,070	146%	–
Dominion Resources Inc.	138%	3,877,650	(258,070)	93%	–
Southern Company (The)	135%	5,943,000	(526,410)	91%	–
SCANA Corporation	132%	740,040	(80,095)	89%	–
Energy East Corporation	129%	2,360,198	(296,975)	87%	–
Xcel Energy Inc.	120%	2,795,897	(533,643)	81%	–
FirstEnergy Corp.	111%	4,987,500	(1,235,150)	75%	176,450
American Electric Power Company, Inc.	110%	4,314,450	(1,116,610)	74%	159,516
Northeast Utilities	109%	2,369,745	(623,571)	74%	89,082
CenterPoint Energy, Inc.	109%	1,727,250	(454,930)	74%	64,990
Edison International	107%	3,522,750	(968,880)	72%	138,411
PG&E Corporation	105%	9,535,050	(2,761,650)	71%	394,521
NiSource Inc.	104%	2,266,740	(677,618)	70%	96,803
DTE Energy Company	103%	3,202,500	(979,490)	69%	139,927
Duquesne Light Holdings, Inc.	102%	864,885	(266,497)	69%	38,071
PPL Corporation	102%	5,758,200	(1,782,200)	69%	254,600
Integrys Energy Group, Inc.	101%	1,270,710	(404,865)	68%	57,838
Duke Energy Corporation	100%	4,516,050	(1,448,140)	68%	206,877
NSTAR	99%	1,110,276	(365,218)	67%	52,174
OGE Energy Corp.	99%	548,100	(183,018)	67%	26,145
Consolidated Edison, Inc.	97%	9,130,800	(3,166,800)	65%	452,400
Pepco Holdings, Inc.	96%	1,785,840	(627,546)	65%	121,027
Sierra Pacific Resources	95%	708,421	(254,024)	64%	48,990
Public Service Enterprise Group Incorporated	94%	3,781,050	(1,374,150)	64%	265,015
Progress Energy, Inc.	93%	2,249,100	(831,940)	63%	160,446
Tennessee Valley Authority	93%	9,027,900	(3,364,230)	63%	648,816
Exelon Corporation	92%	10,948,350	(4,108,210)	62%	792,298
Hawaiian Electric Industries, Inc.	91%	1,048,541	(404,361)	61%	77,984
Sempra Energy	91%	2,930,550	(1,135,670)	61%	219,022
Energy Future Holdings Corp.	90%	2,451,750	(955,070)	61%	184,192
TECO Energy, Inc.	88%	585,060	(235,243)	60%	45,368
Ameren Corporation	88%	3,229,800	(1,314,220)	59%	253,457
Allegheny Energy, Inc.	87%	1,158,885	(474,303)	59%	91,473
Wisconsin Energy Corporation	87%	1,219,050	(503,938)	59%	97,188
AES Corporation, (The)	82%	5,114,550	(2,262,480)	56%	436,335
Entergy Corporation	82%	3,551,335	(1,588,481)	55%	306,350
Westar Energy, Inc.	78%	701,439	(329,981)	53%	63,639
Great Plains Energy Incorporated	78%	538,545	(254,474)	53%	49,077
Pinnacle West Capital Corporation	77%	1,806,886	(870,440)	52%	167,870
Constellation Energy Group, Inc.	77%	1,726,410	(832,875)	52%	160,626
American Water Works Company, Inc.	68%	962,844	(518,191)	46%	99,937
CMS Energy Corporation	65%	1,743,000	(977,620)	44%	188,541
Total	**102%**	**129,845,697**	(40,542,207)	**69%**	**6,825,456**

Appendix C: Could the outlook change to negative?

Although we do not foresee a change in outlook for the investor-owned electric utility sector at this time, several possibilities—however remote—pose considerable risks for companies that are not adequately prepared.

- **Legislative or regulatory intervention.** Policy moves that are designed to revise, amend, adjust or completely restructure the existing electric utility market framework can often have a materially negative impact for the sector, especially in those cases if implemented unexpectedly quickly. The scale, scope and depth of an intervention—as well as any unintended consequences—would determine the magnitude of the rating reaction.

  Intervention is most likely to occur on an isolated basis—that is, within a particular U.S. state—and would not have significant implications for the sector as a whole. Federal legislation, however, could affect the entire sector.

- **Mismanaged liquidity.** Maintaining adequate sources of liquidity availability is critical. The sector's working capital requirements are often exposed to enormous swings, which, if not properly managed, could destroy a company's credit ratings. We believe utilities will approach their liquidity needs in a reasonably conservative manner, in part due to regulatory commitments to maintain reliability.

  Even so, mismanaging liquidity would pressure the sector's outlook severely. And although we would only expect to see mismanaged liquidity on an isolated basis, posing no significant impact to the sector, investor-owned electric utilities tend to be managed in similar ways. Therefore, a sudden federal intervention could conceivably expose a widespread lack of adequate liquidity.

- **Financing capital expenditures.** OpCo[9] is set to invest about $4.2 billion over the next five years. In September 2008 the company held $6.3 billion of net property, plants and equipment, and $8.7 billion in total assets. This level of investment will need to be financed, since the sector does not produce enough cash flow to cover its investment needs (let alone its dividends).

  We believe utilities will begin to finance their needs with a more balanced mix of debt and equity than we have seen to date. An over-reliance on debt as the primary financing source may stretch the sector's financial metrics and pressure its outlook. Unlike the risks noted above, financing decisions are longer-term risks. We believe most utilities now have time to revise their financing plans before this risk translates into sector-wide downgrades.

[9] This hypothetical company is derived from composite industry results (see page 3).

Moody's Related Research

Industry Outlooks

- EMEA Electric and Gas Utilities, November 2008 (112344)
- US Coal Industry Outlook – 2009, October 2008 (112070)
- North American Natural Gas Transmission & Distribution, September 2008 (111486)
- U.S. Investor-Owned Electric Utilities: Six Month Update, July 2008 (109675)
- North American Natural Gas Transmission & Distribution: Six-Month Industry Update, March 2008 (108212)
- U.S. Electric Utility Sector, January 2008 (107004)
- US Coal Industry Outlook – 2008, October 2007 (105372)
- North American Natural Gas Transmission & Distribution, September 2007 (104854)
- U.S. Electric Utilities, December 2006 (101304)

Special Comments

- Carbon Dioxide: Regulating Emissions Following a Long and Winding Road, November 2008 (112822)
- U.S. Investor Owned Electric Utilities Somewhat Insulated (but not immune) from market stress, September 2008 (111891)
- New Nuclear Generating Capacity: Potential Credit Implications for U.S. Investor Owned Utilities, May 2008 (109152)
- EU Climate Change Strategy, May 2008 (108846)
- Decommissioning and Waste Costs for New Generation of Nuclear Power Structures, May 2008 (109086)
- New Generating Capacity in a Carbon Constrained World, March 2008 (107453)
- Credit Challenges Ahead For Public Power: Difficult Decisions on New Generation Capacity, November 2007 (105997)
- New Nuclear Generation in the United States: Keeping Options Open vs. Addressing An Inevitable Necessity, October 2007 (104977)
- Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector, August 2007 (103941)
- Environmental Regulations Increase Capital Costs for Public Power Electric Utilities, June 2007 (103616)
- Regulation Of Greenhouse Gases: Substantial Credit Challenges Likely Ahead For U.S. Public Power Electric Utilities, June 2007 (103356)
- Regulatory Pressures Increase For U.S. Electric Utilities, March 2007 (102322)
- Moody's Comments on the Back to Basics Strategy for the North American Electric Utility Sector, November 2006 (100660)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

U.S. Investor-Owned Electric Utilities

Analyst Contacts (continued from page 1):

New York **212.553.1653**

Mike Haggarty **1.212.553.7172**
Vice President /Senior Credit Officer

Mihoko Manabe **1.212.553.1942**
Vice President /Senior Credit Officer

Allen McLean **1.212.553.1942**
Vice President /Senior Credit Officer

A.J. Sabatelle **1.212.553.4136**
Vice President /Senior Credit Officer

Kevin Rose **1.212.553.0389**
Vice President /Senior Analyst

Laura Schumacher **1.212.553.3853**
Vice President /Senior Analyst

Scott Solomon **1.212.553.4358**
Vice President /Senior Analyst

Ed Tan **1.212.553.1097**
Vice President /Senior Analyst

Jim O'Shaughnessy **1.212.553.1607**
Analyst

Wesley (Wes) Smyth **1.212.553.2733**
Vice President/Senior Accounting Specialist

U.S. Investor-Owned Electric Utilities

Report Number: 113690

Author	Associate Analyst	Editors	Production Specialist
Jim Hempstead	Ryan Wobbrock	Scott Stearns Jeff Pruzan	Ida Chan

Moody's Investors Service

FitchRatings
KNOW YOUR RISK

Corporates

Global Power
North America
Special Report

U.S. Utilities, Power and Gas 2009 Outlook

Analysts

Philip Smyth
+1 212 908-0531
philip.smyth@fitchratings.com

Glen Grabelsky
+1 212 908-0577
glen.grabelsky@fitchratings.com

Sharon Bonelli
+1 212 908-0581
sharon.bonelli@fitchratings.com

Robert Hornick
+1 212 908-0523
robert.hornick@fitchratings.com

Ellen Lapson
+1 212 908-0504
ellen.lapson@fitchratings.com

Peter Molica
+1 212 908-0288
peterh.molica@fitchratings.com

Ralph Pellecchia
+1 212 908-0586
ralph.pellecchia@fitchratings.com

Karl Pfeil
+1 212 908-0516
karl.pfeil@fitchratings.com

Table of Contents **Page**

Overview

This report explains Fitch Ratings' business outlook for the U.S. Utilities, Power and Gas sector for 2009 and a longer term that extends through the following three to four years. Outlooks are formulated for industry segments based on fundamental factors. However, rating outlooks for individual companies may vary from segment outlooks due to factors specific to that entity. Segment credit outlooks are summarized below:

- Negative short- and long-term outlooks for the U.S. investor-owned electric utility, power generating and retail propane distributor sectors.
- Stable short- and long-term outlooks for natural gas distribution utilities, natural gas pipelines and midstream natural gas gatherers. The short-term outlook for natural gas processors is negative, and the long-term outlook is stable.
- The short- and long-term outlook for public power entities is stable.

Fitch's sector outlook for 2009 is based on the assumption that the economy will continue to contract next year and that credit markets will gradually stabilize. However, Fitch expects that higher-cost capital and tight credit availability will persist in 2009 and perhaps 2010.

The operating and financial environment for all sectors of the U.S. economy deteriorated in 2008, a year that has officially been designated a recession by the National Bureau of Economic Research. Deterioration of economic activity accelerated in the final quarter of 2008, and the downturn may prove to be the deepest and most prolonged since the 1930s. The spreading global economic downturn, accompanied by global deleveraging, has resulted in the collapse, bailout or forced merger of financial institutions. The broad credit markets are in shambles and access to credit is restrictive, particularly at lower credit ratings. While credit is available to investment-grade issuers in the utilities, power and gas sectors, it is more expensive, particularly when viewed against the easy money environment which prevailed for most of this decade.

The utilities segment is not immune to the economic challenges facing corporate America, but is relatively well positioned. Providing essential services and largely regulated, utilities benefit from investor perceptions as a defensive group. For the most part, electric utilities reduced debt and focused on improving their core business over the past four years. Consequently, while many industries and companies have recently been shut out of the capital markets, stronger utilities have accessed both secured and unsecured markets. However, investor "flight to quality" is selective within the sector, favoring companies at higher rating levels, with a marked preference for secured debt and lending at the operating, rather than parent, company.

The challenging macroeconomic environment is a key component of the negative outlook for the competitive generators. In the face of collapsing commodity and lower wholesale power prices, this largely non-investment-grade sector has seen margin erosion, more restrictive credit availability and significant declines in the market value of their equity. Master limited partnerships (MLPs) lost their cost-of-capital advantages, which underpinned expansionary acquisition and capital expenditure strategies.

Fitch expects the utility parent, regulated gas and electric utilities and pipeline companies to be fairly resilient to macroeconomic pressures. Nonetheless, individual companies that are confidence sensitive or have large financing needs due to capital expenditure budgets, exposure to short-term debt, upcoming debt maturities and/or variable-rate debt may face downward pressure on outlooks or ratings. The "Credit Outlook Summary by Segment" table on page 4 of this report delineates each sector's outlook and median rating with supporting bullet points.

Key Drivers of the 2009 Outlook

The positive and negative factors driving Fitch's outlook in 2009 include:

Positives

- Continued capital market access in a difficult financing environment, particularly for higher-rated regulated utilities and pipelines.
- The decline in commodity prices from record peak levels will ease cost pressures for materials and labor.
- Lower market prices for natural gas and electric power will be neutral to beneficial to electric and gas distribution utilities, and in many cases will reduce working capital needs and cash collateral postings on hedging activities.

Negatives

- Higher marginal cost of debt.
- Depressed equity valuations.
- Liquidity and market access to remain fragile.
- Administration change creates uncertainty about national environmental and tax and dividend policies.
- More stringent implementation of environmental regulations.
- Reduced electricity and gas consumption.
- Lower prices for natural gas and wholesale power, resulting in reduced spark spreads and dark spreads for un-hedged competitive power generators.
- Investor-owned and public power utilities may face resistance from regulators and consumers to rate increases in a recessionary environment.

Rising Weighted Average Cost of Capital

Several investment-grade issuers, mostly 'BBB' to 'A' rated operating companies, have issued senior unsecured debt with financing costs clustered in a range approximating 250 to 450 basis points above the 5% to 6% range of just 12 months ago, and spreads have widened 700–1000 basis points for speculative-grade companies. However, the negative effects of higher capital costs is expected to be muted for most issuers in the sector since only a relatively small portion of debt will re-price in any given year. Thus, Fitch believes the anticipated erosion to interest coverage measures will not result in near-term negative rating or Outlook changes. Conversely, a much smaller group of issuers with large debt maturities or heavy financing needs for new capital expenditures may experience downward pressure on ratings and/or Outlooks.

Electric utility holding company stocks have declined 32% on a year-to-date basis compared to a 35%-40% decline for the broad equity indices. Price declines were greater still for the MLP and competitive generator equities at 50% and 80%, respectively. Equity valuations for most utilities are now at a slight premium to book

value, while the equity prices of competitive generators and MLPs are well below their book values. The sharp increase in the cost of equity capital is a negative credit development, especially in view of the industry's large projected capital expenditure requirements (see the "Capital Spending" section below for more detail) in 2009–2010 and resulting funding needs. Moreover, the expiration of current favorable income tax treatment of common dividends is likely to bring further pressure on equity valuations.

Average authorized returns on equity (ROE) for the regulated utility sector are currently in the 10.25% to 10.5% range, with some jurisdictions approaching 9%. Fitch is concerned that absent a meaningful up-tick in authorized ROE, the industry may have difficulty attracting adequate capital to fund new reliability, infrastructure and renewable energy projects in light of the significant change in capital market conditions and investor expectations. The materially higher cost of capital for competitive energy generators and energy merchants will rule out all but the most essential investment projects for such companies. Similarly, for MLPs, most growth capital expenditure projects or acquisition of existing properties are no longer possible given the substantial diminution in equity valuations.

Electric transmission projects that benefit from favorable Federal Energy Regulatory Commission (FERC) jurisdictional tariffs that produce steady cash flow and higher ROEs will be at a decided advantage in raising new debt and equity capital, along with utilities in states that allow higher ROEs, effective pass-through tariff mechanisms and recovery of a cash return on capital investments prior to completion.

Interest Rates

U.S. Treasury interest rates have declined to historic lows while credit spreads have widened significantly. Assuming that crisis conditions ease and credit markets stabilize in 2009, base U.S. Treasury rates could rise and credit spreads contract somewhat, resulting in approximately flat all-in rates on corporate debt. Fitch's outlook is based on the assumption that higher corporate interest rates are likely to prevail through 2009 and into the foreseeable future.

Inflation and Commodity Prices

Fossil fuel prices (coal, natural gas, oil) are well below the highs reached in mid 2008. Given the weak economic environment and accordingly weak outlook for reduced energy consumption, continued pressure on fossil fuel and wholesale power market prices is likely to persist at least through 2009. Materials and labor, previously in short supply, and under rapid price escalation, have also come down from peak prices. While key material costs, such as fuel, steel and cement, have declined substantially from their early 2008 peak, costs still remain fairly high relative to long-term trends and are comparable to 2007 levels. Further price erosion is possible, however, as the global recession deepens.

Access to Capital and Credit Markets

The power and gas sector for the most part has retained access to the credit markets despite the very restrictive broad credit market in 2008. Fitch expects the sector will continue to be able to access to the credit markets, although individual companies — including non-investment-grade issuers, competitive generators and those with large unregulated, economically sensitive businesses or those that have confidence sensitive operations with large collateral needs — may experience a very restrictive financing environment. Fitch is monitoring expiring bank credit facilities and the pricing, covenants and terms of new and replacement facilities. Despite the sharp re-pricing of and aversion to risk in the investment community, Fitch believes the sector's relatively predictable cash flows offer relative attraction to fixed income investors.

Credit Outlook Summary by Segment

The 12-month segment credit outlooks in the left column reflect fundamental analysis of factors influencing developments in the segment, not the aggregate Rating Outlooks of the entities in the segment. Median ratings indicated are based on the issuer default ratings (IDR) of entities rated by Fitch Ratings, with the exception of the public power utility segment, which is based on senior instrument ratings. Public power utilities are not assigned IDRs.

Segment	Drivers in Credit Outlooks for 2009
Utilities	
Utility Parent Companies Median IDR: BBB **Credit Outlook** Negative	• Dividends from utility subsidiaries are limited by substantial capital programs. • Dividends from wholesale generation subsidiaries, particularly owners of coal and nuclear generation, are expected to weaken from last year's robust levels, reflecting lower power price realizations and margins. • Significantly elevated cost of capital and tight credit markets will challenge merchant and utility subsidiaries that have substantial external capital requirements. • Less pressure on fuel, labor and material costs compared to prior years.
Electric Utilities, Investor-Owned Median IDR Integrated Electric: BBB Median IDR Electric Distribution: BBB+ **Credit Outlook** Negative	• Conservative corporate strategies focused on risk reduction. • Regulatory environment remains a key driver of credit quality. • External funding needs due to significant capital investment in transmission, environmental projects and gas-fired capacity additions. • Interest rates likely to remain at recent elevated levels. • Relatively little baseload construction. • Fuel and purchased power cost volatility due to growing reliance on natural gas-fueled generating capacity. • Pockets of regulatory or political resistance, particularly in restructured states.
Gas Distributors, Investor-Owned Median IDR: A– **Credit Outlook** Stable	• Robust gas storage heading into the 2009 winter season. • Consistent regulatory treatment and manageable capital spending and external funding requirements. • Concerns include the negative effect of conservation on unit volumes and rising bad debt expense.
Competitive Generation Companies	
Generating Companies and Energy Trading Median IDR: BB– **Credit Outlook** Negative	• Challenging credit markets for speculative issuers; tighter liquidity. • Lower operating cash flows, albeit from relatively high levels. • Strong asset values driven by shrinking capacity reserve margins, and higher market heat rates. • Movement away from competitive markets in certain states and potentially rising environmental costs are sources of concern for investors. • Self funding of capital spending plans due to cut backs of major capital commitments in the face of tight credit.
Natural Gas Midstream Companies	
Midstream and Pipeline Companies Median IDR: BBB– **Credit Outlook (Pipelines)** Stable **Credit Outlook (Midstream)** Stable for Natural Gas Gatherers Negative for Natural Gas Processors **Credit Outlook (Propane)** Negative	• Adequate near-term liquidity, helped by recently expanded bank facilities. • Aggressive natural gas pipeline budgets, increased construction costs and unfavorable capital markets could result in moderate near-term weakening in credit measures. • The 2009 outlook for Midstream Services companies is mixed. Gas gatherers should continue to benefit from ongoing domestic production increases. Processors, however, face the probability of material, commodity-driven margin pressure in 2009 and a negative outlook. • The negative outlook for Retail Propane Distributors continues in 2009, reflecting the anticipated negative effect of customer conservation on unit volumes.
Public Power Utilities	
Municipal, State and Federal Agencies and Cooperatives Median Rating (Retail Systems): A+ Median Rating (Wholesale Systems: A **Credit Outlook** Stable	• Local control over rate-setting without state commission oversight and continued willingness to recover costs in rates on a timely basis. • A cost advantage compared to neighboring investor-owned utilities. • Benefits associated with predominantly residential and commercial customer bases. • Near-term pressures associated with capital market access and effects of a prolonged economic downturn. • Need for additional baseload generation, together with developing environmental policies and the associated capital cost impact on individual systems.

Source: Fitch.

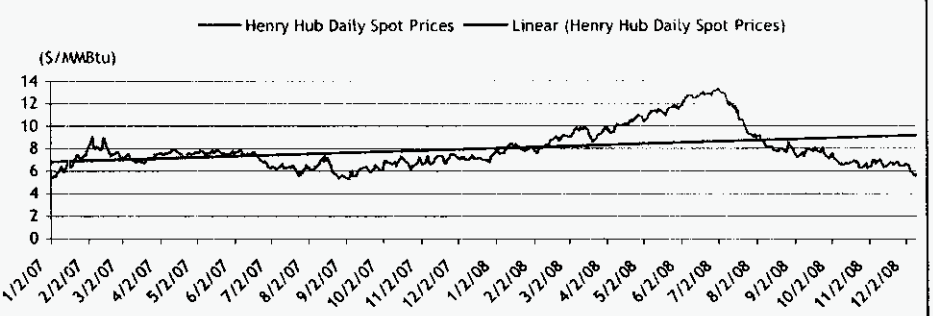
Other Key Drivers

In addition to the macroeconomic drivers already cited, companies within the utilities, power and gas sector are sensitive to a number of sector-specific variables. These drivers can have varied effects on different types of entities within the sector. For example, adverse conditions for a producer or generator may be beneficial for a downstream distributor.

Natural Gas Price Environment

From their September 2007 low of $5.29, spot natural gas prices as reported at Henry Hub rose 150% to $13.31 in early July 2008 and declined 57% to $5.68 per million British thermal unit (mmBtu) on Dec. 10, 2008. The sharp run-up and subsequent collapse of natural gas prices in 2008 is emblematic of the extreme price volatility that characterizes the commodity and is likely to persist in the future. Fitch believes natural gas prices will continue to experience an upward price bias in the longer term, punctuated by bouts of volatility not unlike the September 2007–December 2008 experience.

Henry Hub Daily Spot Price
(Jan. 2, 2007–Dec. 10, 2008)



MMBtu - Million British thermal units.
Source: Bloomberg, Fitch.

Early in 2008, high natural gas prices relative to historical norms, combined with exploitation of new North America shale reserves, resulted in a new market perception that unconventional sources such as shale formations may be more prolific in the near to intermediate term than previously supposed. At the same time, market participants began to expect reduced demand as a global recession became more likely over the course of the year. Natural gas will enter 2009 approximately 60%–70% below its 52-week high.

Low gas prices form an adverse environment for owners of oil, gas or coal reserves and unregulated electric generation fueled by coal or uranium. On the other hand, low gas prices are generally favorable for consumers of gas and electricity and integrated electric utility companies. Interstate gas pipelines are relatively insensitive to changes in gas prices. For most electric utilities, commodity costs are a pass-through to ratepayers and neutral to their bottom lines, but lower natural gas prices have the beneficial effect of ameliorating upward pressure on consumer rates.

In Fitch's view, current low natural gas prices are unlikely to prevail in the long term, since producers are not likely to bring to market new gas production from more costly unconventional sources if current, or lower, market prices for natural gas persist. Other factors that are likely to increase prices in the next up-cycle are higher demand for gas for power generation, as few new coal generating units will be built over the next five years, dwindling deliverability of conventional gas sources and the higher cost of producing gas from unconventional sources. Fitch's outlook assumes the price of natural gas is likely to approximate the $6–$8 per mmBtu range, consistent with the current forward price curve for natural gas at Henry Hub, La. A return to a tighter supply/demand balance as world economies work their way out of recession would set the stage for a resumption of volatility similar to past episodes of supply interruption.

Power and Gas Demand Reduction

After adjusting for mild weather, demand growth for both electricity and natural gas appears to have softened in 2008, and opinions vary as to whether the primary cause was voluntary consumer reaction to higher prices and pressures on household budgets, recessionary impacts affecting commercial and industrial demand, reduced housing occupancy rates as lenders foreclosed on residences in some hard-hit regions, or the spread of policy-driven programs that encourage energy efficiency and demand reduction. Most likely, all of these played some role in dampening demand. The outlook is for weak demand to continue in 2009, as the recession will continue to reduce consumer disposable income and affect industrial and commercial loads.

There has been a trend in recent years of lower natural gas demand due to shrinking consumption by industrial users, offset by higher usage for power generation. Continuing increases in penetration of power generation by natural gas is expected to offset shrinkage in primary demand for gas as a fuel for residential, commercial and industrial applications, as natural gas is likely to be the fuel of choice for new power plant construction for the next few years.

Per capita electricity demand growth is likely to be flat over the next three to four years due to increased political support for and public adoption of energy efficiency and electric load management programs. Programs take a wide variety of forms, including new investment programs to replace customer meters, higher efficiency standards for new residential or commercial construction and new types of tariffs that encourage energy efficiency and conservation. Fitch believes these programs may receive a significant boost at the national level with the anticipated change in the presidential administration in early 2009, a larger Democratic majority in the U.S. Congress and change in Congressional leadership. In the long term, it remains to be seen whether electric-powered vehicles or other new applications of electric power will spur new consumption patterns in 2015–2025. The Department of Energy (DOE) loan guarantee program to encourage the commercial deployment of clean energy technology could also expand significantly under the Obama administration.

For distribution utilities and integrated utilities, the effect of slower growth or declines in sales of power and gas will have differing effects on operating cash flow for utilities in different jurisdictions. Some utilities can adjust their tariffs frequently to offset volume variances. Special tariff mechanisms that make utility cash flows insensitive to volume variations are common but not universal for gas distribution utilities and are rarer for electric utilities. For companies without such "tariff decoupling," slower growth or actual decline in sales makes it more difficult for utilities to recover their fixed costs. As state and federal policies increasingly favor energy efficiency and demand-reduction programs, electric utilities are likely to press for tariff decoupling mechanisms to replicate those now in effect for some natural gas distributors.

Electric Power Capacity

Electric power reserve capacity margins on average have been declining for the past several years, since even small increases in power consumption exceed the minimal net additions to North American power generating capacity. Recent additions to electric power capacity in the U.S. have been predominantly natural gas and wind generation. With recession and reduced consumer purchasing power dampening consumption trends, the expected growth in U.S. power demand during 2009 is likely to fall below Fitch's long-run forecast rate of 1.6% on average and could fall to zero or even a slight decrease.

This slowing of demand will temporarily delay the perceived need for new electric power generation, but the lead time for building new baseload capacity is anywhere from four to 10 years, and the need for additional baseload capacity will become especially evident in 2011–2013. Over the next several years, Fitch expects natural gas to be the de facto fuel of choice for new build generation given the political uncertainty and long lead time to develop new coal or nuclear generating facilities.

Capital Spending

Capital investment budgets at utility holding companies grew at a 14% compound annual rate during 2003–2007 and are expected to remain at elevated levels in 2008 and beyond. Factors underlying the higher capital investment trend include the need for continued infrastructure reliability spending, investment in renewable energy projects and environmental remediation. Factors expected to offset growth in capital budgets include slowing unit power sales in the near term (due to weak economic conditions) and commodity cost deflation, as well as management efforts to minimize external funding requirements.

Pension Funding

Pension funding is unlikely to become a crucial economic issue for companies in the utility, power and gas sector, for the following reasons:

- Most regulated utilities have one or more defined benefit plans that had been either adequately funded or over-funded prior to the current decline in equity and debt valuations. Regulated utilities are able to recover their pension costs as a component of the base tariff, a factor that helps the companies offset the cost in the long run, but does not exempt them from having to comply with the funding rules under the U.S. Pension Protection Act of 2006. As a capital-intensive sector, employment levels and labor costs are not material to current operating results and future pension funding.
- By and large, energy merchants, midstream gas companies and competitive generation companies tend to be younger companies with more modern defined-contribution pension plans. If such companies have any under-funded defined benefit plans, these tend to cover a minority of their employees, and the obligations are relatively small.

However, the precipitous drop in the values of pension assets in 2008 may render many defined benefit plans under-funded.

Under the Pension Protection Act of 2006, employers must contribute enough money to their plans each year so that liabilities will be fully funded after seven years. Under the 2006 law, a 100% target will be phased in so that in 2008, employers only had to hit a 92% funding target, while in 2009, the funding target will be 94%. In December 2008, Congress passed a bill (the Worker, Retiree, and Employer Recovery Act of 2008, H.R. 7327) that modifies the funding requirements of the 2006 law. Among other things, the

2008 law will relieve employers of the requirement to bring their pension funding up to 100% if their funding level is below the 2009 target of 94% and requires them only to restore their 2009 assets to the target level. The law also permits companies to assume higher returns on their pension assets than would otherwise have been the case. The result will reduce but not eliminate the need for companies to top-up depleted defined benefit pension plans to the 94% level. As of Oct. 31, 2008, the Milliman Index of 100 largest U.S. pension plans had declined 23% from the value at the end of 2007, and the index-funded ratio for the index had declined from 102.7% to 91.7%.

State Political and Regulatory Risk

The typical operating utility's regulatory/political environment is central to the credit rating process. The current restrictive credit environment, combined with elevated capital budgets, is expected to put upward pressure on rates over the coming five-year period, notwithstanding the recent pull-back in commodity prices from record high levels. Regulatory risk remains a recurring theme for this year's outlook, as the pressure of a weak economic backdrop could result in political push-back to rate increase requests.

All else equal, utilities operating in more balanced regulatory jurisdictions providing high-quality customer service are more likely to earn reasonable returns on investment and achieve higher creditworthiness. Conversely, utilities with suboptimal regulatory outcomes are more likely to experience lower relative returns, higher financing costs and relatively anemic credit profiles. In evaluating a utility's ability to earn a reasonable return on investment, Fitch considers the degree of regulatory lag and utilization of automatic recovery mechanisms. The vast majority of states have implemented tariffs designed to recover fuel and purchase power costs on a standardized basis, and many have applied such tariffs to the recovery of other costs, such as FERC-approved transmission and/or environmental costs.

Utilities operating under transition plans that include multi-year rate freeze or cap provisions are particularly vulnerable to event risk associated with state regulatory and political reaction to rate increase requests to recover higher commodity, capital and operating costs. While only a relatively small number of utilities operate under such provisions, potential trouble spots exist in Pennsylvania and Ohio, where utilities are coming to the end of multi-year restructuring transition plans. Jurisdictions such as California and Utah, and states in the Southeastern U.S. have adopted procedures that facilitate reasonable authorized returns, timely rate changes, utilizing forward test years, balancing accounts and cost-recovery mechanisms.

U.S. National Energy Policy

Profound changes in energy policies and environmental regulations are likely to result from the upcoming change of presidential administration, changes in Democratic leadership in the House of Representatives and a wide Democratic legislative majority. Accelerating political support for carbon emissions reductions to combat global climate change is expected to result in enactment of carbon legislation to dramatically reduce emissions late next year or in 2010, but the structure, timing and implementation is still uncertain.

The incoming head of the Environmental Protection Agency (EPA) Lisa Jackson is expected to take a more vigorous approach to enforcing the Clean Air Act, perhaps in the following areas: replacing the Clean Air Interstate Rule and Clean Air Mercury Rule; defining carbon dioxide or other greenhouse gases as pollutants subject to regulation under the Clean Air Act; undoing regulations put in place during the Bush administration, including any "midnight regulations" implemented in the final days.

Recent Obama-administration selections for various energy posts include the nomination of research scientist Steven Chu for secretary of energy and former Clinton administration EPA chief Carol Browner for the newly created position of the administration's top coordinator of energy policy ("energy czar") indicate strong support for green initiatives.

The vote by House Democrats to replace Rep. John Dingell as head of the House Energy Committee with Rep. Henry Waxman of California presages mounting support in the House to pass a stringent law to control greenhouse gases. Fitch notes that Speaker of the House Nancy Pelosi (D-Calif.) strongly supports energy conservation and renewable resources, opposes the use of fossil fuels to generate power and drilling for oil and gas in wilderness areas. Significant Senate committees that will be involved in a renewed effort to pass laws to control carbon dioxide are: Committee on Environment & Public Works, under the leadership of Sen. Barbara Boxer (D-Calif.) and the Committee on Energy & Natural Resources chaired by Sen. Jeff Bingaman (D-N.M.). These leadership positions and the solid Democratic majority increase the likelihood that Congress will pass legislation restricting carbon emissions that will ultimately be signed into law by President-elect Obama in 2009 or 2010.

In Fitch's view, Congressional leadership is likely to press for a national renewable energy portfolio standard, energy efficiency and conservation initiatives and is unlikely to support new nuclear power initiatives, development of cleaner coal technologies and carbon capture and storage. However, opposition could emerge from Congressional Democrats concerned about the impact of carbon restrictions on jobs and industrial competitiveness. Meanwhile, the steep cost associated with government programs to rescue the U.S. financial system, ongoing recession and the incremental expense associated with the implementation of green programs could affect the shape and timing of any new programs. In addition, the general appeal of a cap-and-trade mechanism may have been tarnished by the public's growing disenchantment with "deregulated" markets and concerns regarding potential for manipulation by traders in a new market for emissions allowances.

Bankruptcy and Restructuring

Valuations of power and gas assets have declined from their peak in 2007, but even at the lower levels that result from tight credit conditions and a higher cost of capital, asset values are still meaningful. As a consequence, companies in the sector have some ability to negotiate with creditors, pledge assets or restructure debt, even under stressful circumstances.

The bankruptcy petition of SemGroup and its major wholly owned subsidiaries in the U.S. on July 22, 2008, was the sole notable bankruptcy filing in the power and gas sector in 2008. SemGroup is a privately held midstream energy partnership focused primarily on providing gathering, transportation, processing and marketing services for crude oil and refined products in the U.S. Midcontinent region and Canada. SemGroup experienced severe liquidity strains following a spike in crude oil prices. The company will likely sell some assets or businesses and is attempting to form a plan of reorganization.

Utility Parent Companies

2009 Outlook — **Negative**
Longer-Term Outlook — **Negative**

The 2009 and longer-term operating and financial outlook for the utility parent companies reflects the increasingly challenging operating environment for the group's regulated and unregulated businesses and difficulty in accessing capital at a reasonable cost. Please refer to the individual sections of this report regarding the electric utility,

gas distribution and competitive generation companies and their respective operating and credit outlooks.

The credit environment for utility parent and holding companies (UPCs) turned significantly more challenging during the second half of 2008 as capital market conditions deteriorated and major world economies, including the U.S., entered cyclical downturns. Continued access to capital at reasonable rates in 2009 remains uncertain at a time when many utility holding groups have historically high capital investment programs and will require ongoing access to reasonably priced capital in order to fund new investment and refinance maturing debt. Despite these challenges, the essential nature of UPC services, regulated franchises and greater comparative earnings and cash flow predictability position the industry favorably relative to other industries, in Fitch's opinion.

While UPCs have considerable flexibility to reduce unregulated capital investment projects, Fitch believes the vast majority of planned utility investment, primarily earmarked for reliability, environmental and renewable energy projects, is largely non-discretionary and likely to remain at historically high levels for the foreseeable future. Challenges associated with significantly higher utility holding group capital requirements are compounded by the dramatically altered capital markets compared with last year's more benign conditions.

Year to date, utility stocks, as measured by the Philadelphia Utility Index, have declined 32%. Nonetheless, high comparative dividend yields, manageable payout ratios, comparatively stable earnings and cash flow and less dramatic stock price declines relative to broader stock indices should enable UPCs to attract equity capital, albeit at considerably higher cost compared to year-ago levels.

Bond spreads have widened meaningfully for UPCs at the lower end of the investment-grade spectrum and/or with below-investment-grade credit ratings. Such entities face significant financing risk as the result of restrictive credit markets. Access to credit at the parent level is unavailable for all but the most creditworthy UPC issuers. In November 2008, Dominion Resources, Inc. (D, rated 'BBB+' with a Stable Rating Outlook) issued $600 million of 8.875% senior notes due 2019 and Sempra Energy (SRE, 'A'/Stable) issued $750 million of senior unsecured debt in November 2008, comprised of $250 million of 8.9% notes due 2013 and $500 million of 9.8% notes due 2019.

Notwithstanding adverse capital market conditions and other challenges, ratings in the UPC sector were generally stable in 2008, reflecting the sector's relative earnings and cash flow stability. The UPC's median 'BBB' issuer default and senior unsecured debt ratings, respectively, are the same as a year ago. In 2008, there were four downgrades, compared with three upgrades in the sector. Approximately 77% (37 of 48 observed companies) of Fitch's UPC issuers have Stable Rating Outlooks, and 10% (five of 48) have Negative Outlooks or are on Negative Watch.

Sector downgrades reflected unfavorable regulatory outcomes and deteriorating coverage ratios in the case of Consolidated Edison (ED, BBB+/Stable) and PNM Resources (PNM, 'BB'/Stable). Regulators in New Mexico and New York authorized 9.1% returns on equity for ED and PNM, respectively, in the companies' last general rate cases. These allowed returns on equity are among the lowest in the industry and are more than 100 basis points below the industry average, presenting a significant challenge to the ability of ED and PNM to attract needed capital in a competitive marketplace. PNM's creditworthiness was also harmed by losses incurred at its unregulated energy supply business.

Fitch also lowered Constellation Energy Group Inc.'s (CEG, 'BBB'/Rating Watch Evolving) credit ratings earlier this year due to energy trading risk management and liquidity uncertainty. On a more positive note, TECO Energy (TE, 'BBB-'/Stable) and CILCORP (CIL, 'BBB-'/Stable) were upgraded in 2008, reflecting reduced parent company debt and a constructive rate order, respectively.

Mergers, Acquisitions and Divestitures

The case for industry consolidation is supported in the longer term by the fragmented nature of the industry, relatively predictable utility cash flows and greater flexibility provided under the Energy Policy Act of 2005 (EPAct 2005), which eliminated certain domestic geographic restrictions and roadblocks to foreign ownership.

However, significantly higher interest costs, lower equity valuations, tight credit markets, global recession and a stronger dollar are among the key factors that argue against accelerating merger and acquisition (M&A) activity in the near-to-intermediate term, in Fitch's view. The thirst of infrastructure and private equity funds for utility and power assets seems to have evaporated along with positive returns as a result of the ongoing credit crisis. Nonetheless, Fitch believes strategic M&A will continue, as evidenced by recent competing bids to acquire CEG or a portion of its assets from MidAmerican Energy Holdings Company (MEHC, 'BBB+'/Stable) and Electricite de France (EDF, 'AA-'/ Rating Watch Negative) and Exelon's (EXC, 'BBB+'/Rating Watch Negative) hostile bid for NRG Energy (NRG, 'B'/Rating Watch Evolving).

Last week, CEG's board of directors terminated its merger agreement with MEHC and accepted a transaction with EDF, in which EDF will acquire a 49.99% ownership interest in the nuclear generation business of CEG. With the early December 2008 EDF bid, Fitch placed the ratings of CEG on Rating Watch Evolving, reflecting uncertainty associated with the EDF bid. Please refer to the Dec. 17, 2008, press release "Fitch Comments on Constellation Energy Transactions" for further information. No rating action was taken by Fitch with regard to MEHC's credit ratings, which were affirmed in September 2008, following the announcement of the proposed agreement to acquire CEG.

On Nov. 11, 2008, EXC launched a hostile bid for NRG, following rejection by NRG of its $6.2 billion friendly bid, initially proposed on Oct. 19, 2008, to acquire all of NRG's outstanding common stock in a fixed-stock transaction. Fitch Ratings placed EXC on Rating Watch Negative on Oct. 20, 2008 and continued NRG on Rating Watch Evolving. The ratings actions in the case of EXC reflect concern regarding the assumption of $8 billion of NRG debt under the proposed transaction. The NRG rating action considers the constructive effect of the bid by more highly rated EXC, while recognizing the unresolved nature of the offer and the potential emergence of another suitor or other corporate actions that could derail EXC's proposed acquisition of NRG. The tender offer expires Jan. 6, 2009. Fitch initially placed NRG on Rating Watch evolving in May 2008 when the company announced its unsolicited bid to acquire Calpine Corp. (CPN) in an all-stock transaction. CPN subsequently rejected NRG's offer.

Other pending deals include the proposed sale of PNM Resources' (PNMR, 'BB'/Stable) natural gas distribution business in New Mexico to Continental Energy Systems, which was announced Jan. 15, 2008. PNM Resources and major intervenors reached a settlement regarding the proposed sale that was approved by New Mexico regulators on Dec. 11, 2008. The sale of PNMR's natural gas distribution business is expected to close in January 2009. For further information, please refer to Fitch's Public Service Company of New Mexico reports dated April 24, 2008, and Nov. 3, 2008.

Parties to state regulatory proceedings to approve the sale of Puget Energy to Macquarie have reached a settlement that is pending a final Washington Utilities and Telecommunication Commission ruling, which is expected before year-end.

Transactions completed in 2008 include the sale of Energy East (EAS, 'BBB'/Stable) to Iberdrola S.A. in September and the sale of Aquila electric and gas assets to Black Hills and Great Plains Energy in July. In addition, a 20% interest in Oncor Electric Delivery Company, a subsidiary of Energy Future Holdings Corp., to an investment group led by Borealis Infrastructure Management. Great Plains also closed the sale of an unregulated subsidiary to Centrica, PLC.

Electric Utilities

2009 Outlook — **Negative**
Longer-Term Outlook — **Negative**

In Fitch's view, the business climate for the electric utility sector is negative in both 2009 and the longer term. A deepening global recession, ongoing financial crisis and a meaningful increase in the cost of capital compound an already difficult operating environment characterized by large projected capital expenditures and commodity cost volatility. Despite the challenges, utilities have relatively stable cash flows vis-à-vis other industries and should benefit in relative terms as investors seek safer investments in a difficult macroeconomic environment. Electric utilities have demonstrated continued access to commercial paper and term debt markets throughout the recent market turmoil, albeit at higher cost. In addition, most companies in the sector are relatively well capitalized with simplified business strategies, which should alleviate pressure on credit ratings.

Jurisdictional regulatory practices will be a key of creditworthiness in the sector. Utilities operating in states with regulatory mechanisms in place that facilitate timely recovery of costs and a reasonable return on investment in rates are more likely to come through this period of stress with limited deterioration of credit quality. Conversely, the ratings of utilities operating in states with relatively low authorized ROEs and significant regulatory lag are more likely to suffer credit deterioration. In general, states with well-defined regulatory practices that facilitate timely general rate case decisions and utilize special tariffs and balancing accounts to adjust rates outside of a general rate case proceeding will, all else equal, support a higher level of relative creditworthiness. Fitch is concerned that the recent rapid escalation in the cost of capital will not be reflected on a timely basis in utility rates.

The regulatory compact is especially important in view of the sector's need for capital to support its projected, large post-2008, mostly non-discretionary capital spending programs. Recent changes in the political landscape articulated above enhance the prospects of higher environmental spending, including carbon controls. Moreover, Fitch is concerned that exclusive reliance on renewable energy and natural gas-fired generating resources will lead to sharp increases in the cost of power to consumers.

Liquidity stands out as a bright spot in an otherwise dreary outlook. The majority of utilities have adequate credit facilities with long-dated maturities and reasonable credit terms that could not be replicated under current market conditions. Debt maturities tend to be well laddered, minimizing the need for substantial refinancing at today's higher rates. Moreover, throughout the credit market turmoil electric utilities have been able to access capital markets, albeit at higher cost. Recent issuance by

Pacific Gas & Electric Co. (PG&E), Virginia Electric and Power Co. (VEPCO), Duke Energy Carolinas (DEC) and Alabama Power Co. (APC) priced well-above similar bonds issued a year ago.

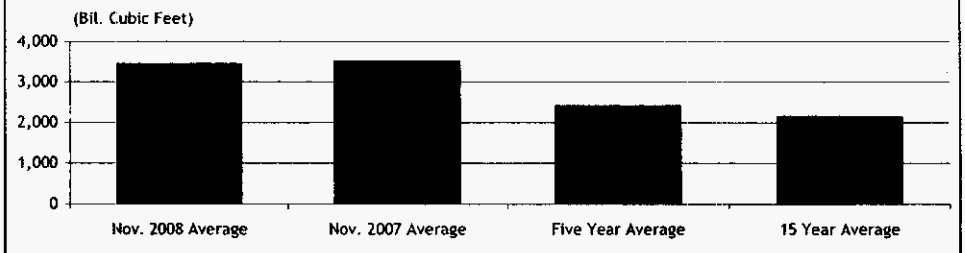
PG&E and DEC issued 10-year bonds that were 280 basis points and 175 basis points higher than their respective 10-year bonds issued in November 2007; VEPCO issued 30-year debt that was 250 basis points higher than a similar issue a year ago; and APC issued five-year debt at 95 basis points above a year ago. Moreover, there is a back log of issuance that is likely to continue to place upward pressure on funding costs. If funding costs remain at these levels, significantly higher regulated returns will be required to continue to attract capital on reasonable terms for needed investments.

Natural Gas Distributors

2009 Outlook — **Stable**
Longer-Term Outlook — **Stable**

Fitch's 2009 outlook for local gas distribution companies (LDCs) is stable. LDCs enter the 2008–2009 heating season positioned similarly to last year. Operating, regulatory and financial fundamentals remain stable. Storage levels, while slightly below last year's levels, are higher than the five-year average. Natural gas prices have moderated, falling from their mid-year 2008 peak, but LDCs that built inventories during the summer will likely be passing higher average costs on to ratepayers this winter season. The current capital market turmoil has highlighted the importance of access to liquidity across all sectors. However, with relatively low maintenance capital expenditure requirements and external financing needs, Fitch believes that there is adequate company financial liquidity across the LDC space.

Weekly Lower 48 States Natural Gas Working Underground Storage



Source: EIA of the U.S. Department of Energy.

Given the regulated nature of the LDC business and generally beneficial rate design, earnings and cash flow generated by LDCs are expected to remain steady for 2009. State regulatory relations, despite the long-term increase in gas supply costs, continue to be constructive for gas LDCs. Capital expenditures by LDCs, for system maintenance and expansion, have remained fairly steady in prior years, and while ongoing capital expenditures are increasing at a moderate rate, it is expected that LDCs will keep a closer eye on discretionary capital expenditures and scale back appropriately given current financial market conditions. Additionally, gas LDC growth projects tend to have a short duration and a relatively small scale and thus generally avoid rate shock. LDCs appear to have adequate liquidity despite restrictive credit market conditions.

With gas prices spiking in mid-2008, several LDCs took the precaution of expanding existing credit facilities or adding new short-term credit facilities to meet additional liquidity needs ahead of the winter heating season, albeit at higher rates. When gas prices fell from mid-year highs, these precautionary steps appeared less necessary, but will provide a liquidity buffer should gas prices move unexpectedly higher this winter. Commercial paper markets, which many LDCs typically rely on to fund supply purchases, have become more costly and limited, and as a result many LDCs have been utilizing their revolvers to fund supply purchases.

Potential concerns for the 2009 outlook relate to bad debt expense and the impact of customer conservation. Bad debt expense has been creeping higher in recent quarters, but remains within historical ranges for LDCs. However, pass-through of higher gas prices to ratepayers, due to historically high priced summer inventory purchases, coupled with a recessionary economy could lead to higher than expected bad debt expense. The Energy Information Administration (EIA) is currently projecting a 3.6% average increase in heating bills for residential customers in the winter of 2008–2009, well below its 18% average increase projection from October 2008. While actual bills could be exacerbated by a colder-than-expected winter, Fitch believes bad debt expense concerns should not have significant near-term financial effects. Natural gas prices have moderated, LDCs have taken proactive steps to more aggressively manage collections and in several cases have requested higher bad debt allowances from regulators, and the federal government has increased funding to the Low Income Home Energy Assistance Program (LIHEAP), all of which will help LDCs contain bad debt expense growth.

Conservation, meanwhile, continues to be an industry-wide concern, and rate design mechanisms crafted to address usage concerns remain on the forefront of several regulatory jurisdictions. Currently, 13 states have approved the implementation of full revenue decoupling, which helps prevent margin erosion stemming from declines in customer usage due to conservation or energy-efficiency increases. Additionally, more than half of U.S. states have some form of either full decoupling or weather normalization, which helps stabilize revenue from the effects of weather. These rate designs help insulate the utility's cash flow from changes in volume of sales, providing earnings and cash flow consistency and stability. From a credit perspective, Fitch continues to view the implementation of rate mechanisms that reduce cash flow volatility favorably; more predictable cash flow translates to lower business risk for LDCs. Decoupling mechanisms can also serve to more closely align an LDC's interests with the growing political groundswell for conservation.

Competitive Generation Companies

2009 Outlook — **Negative**
Longer-Term Outlook — **Stable**

Fitch's 2009 outlook for competitive generators is negative, with more stressful conditions facing the independent generators. Based on the different strategies, financial structures, debt leverage and credit ratings of the companies, Fitch typically views this segment in two subgroups: the affiliated generators and independent generators. Affiliate generators are subsidiaries of either large utility holding companies or financial institutions and, with few exceptions, have investment-grade IDRs ranging from 'BBB–' to 'BBB+'. Ratings reflect well-capitalized balance sheets, relatively favorable capital market access and adequate liquidity. Independent generators are standalone companies that generally have speculative-grade IDRs

ranging from 'B' to 'BB'. Ratings reflect weaker balance sheets, lower capital market access and limited liquidity.

The year 2008 proved to be a more challenging operating environment for the power generating companies than anticipated. Heading into the year, Fitch was positive on its outlook for the sector for 2008 and for the longer term, for independent generators in particular. Fitch's expectation that the operating performance improvements and robust free cash flow at independent generators would result in positive ratings implications never materialized. Moreover, while asset valuations remain strong, liquidity concerns, declining power prices and a recessionary economy all weighed on performance at the independent generators throughout the second half of the year, and earnings and cash flow look to be less robust than originally anticipated.

Fitch expects 2009 to be a much more challenging environment for power generating companies. Capital market constraints, declining power prices, a recessionary economy, government/environmental regulation uncertainty, counterparty exposure and liquidity concerns all will continue to weigh on power generating companies throughout the year and could have modest negative implications on current ratings. Over the longer term, Fitch's believes a stable outlook is more appropriate for power generating companies, and industry fundamentals should favor the generators, as limited amounts of new generation comes online over the next five years and the continued narrowing of reserve margins results in widening spark and dark spreads. While the recessionary economy will likely stifle demand growth, a difficult financing environment and uncertainty about future state and national energy policy/carbon rules remain significant deterrents to new generation.

The predominantly non-investment-grade independent competitive generators face a more hostile financing environment in 2009 than the affiliated generators, as market de-leveraging results in a significant re-pricing of risk. Over the near term, liquidity strains stemming from the reduced risk appetites of financial institutions and other prominent counterparties in the merchant energy market could pressure the competitive generators. Over the longer term, accessing capital for these generators will be significantly more expensive, reflecting higher financing costs and weak equity valuations.

Power generators will cut back discretionary capital spending materially for 2009–2010. Several companies have already announced reductions to discretionary capital expenditures in their competitive businesses for 2009, including Ameren, FPL Energy, PPL Energy and Public Service Enterprise Group. Additionally, some generators plan to delay air-quality-control investments to the extent that they were driven by Clean Air Interstate Rule (CAIR) requirements that have been remanded to the EPA by the appellate court, while other companies said that they must continue their environmental spending to meet state standards that remain in force.

Debt maturities in 2009 appear to be manageable, as most issuers do not face any significant refinancing. Longer term, several independent competitive generators will face maturities of debt in the term loan B market. Typical B loans have terms of five to seven years at the longest, with little repayment prior to bullet maturity. While most of the outstanding B loan maturities are still several years away, a prolonged credit market downturn will make it more difficult and/or more expensive for generators to refinance this debt, a source of longer-term concern. Any needs for covenant relief could accelerate re-pricing of risk or refinancing needs.

Asset valuations for all of the power generators are strong relative to outstanding indebtedness. Consequently, while modest downside rating pressure may exist for the lower-rated competitive generators, strong asset valuations would lead to strong

recoveries across the capital structure in case of default. With equity prices not necessarily reflecting the value of underlying assets, Fitch believes there is an increased probability for consolidation and acquisition within this group in 2009, as evidenced already by competing offers for Constellation Energy and Exelon's hostile bid for NRG Energy. Fitch views consolidation as neutral for this segment overall; however, changes in financial leverage and strategic position could have adverse, neutral or favorable consequences for credit quality and would be dependent on the specific terms of the transaction.

Public Power Utilities

2009 Outlook — **Stable**
Longer-Term Outlook — **Stable**

Fitch continues to maintain its stable outlook for the municipal and cooperative sectors (public power) for 2009. Overall, the sector continues to maintain solid credit fundamentals, including: local control over rate-setting without state commission oversight, a cost advantage compared to neighboring investor-owned utilities and benefits associated with predominantly residential and commercial customer bases. However, in the event that current pressures such as limited capital market access, together with increasing economic stress persist long into 2009, a revision in the public power outlook to negative may be warranted. Fitch expects that the average ratings for wholesale and retail utility systems will continue to be 'A' and 'A+', respectively. Fitch has 184 long-term public power ratings, out of which there were 22 positive rating actions and one negative rating action reported for the calendar year of 2008.

Fitch's outlook takes into account increasing negative credit pressures affecting the U.S. public power and cooperative sectors. With the magnitude of industry and market changes realized over the last year, including the housing market decline, credit deterioration of municipal bond insurers, reduced capital market access and increased interest costs, as well as the potential for a prolonged economic downturn, near-term credit pressures have increased for public power utilities. These current issues are in addition to ongoing credit drivers such as volatile fuel costs, the increasing costs associated with building new baseload generation and uncertainties regarding future costs associated with changing "green-based" environmental regulations. Utilities, whether directly mandated by the state (i.e., IOUs) or governed by locally established standards (public power), must now assess how to meet long-term load growth within an evolving environmental and in some ways more restrictive and costlier regulatory framework. While the recent decline in natural gas, oil, coal and other commodity prices are helping to relieve some cost pressures, volatility in these costs still persists, and the long-term trend continues to indicate progressively rising prices.

While Fitch believes that the public power business model will continue to allow these utilities to perform well in 2009 and provide investors with a generally stable credit sector, increasingly negative market and industry factors could adversely impact some systems more than others. The utilities with the greatest credit exposure are those that have large capital improvement needs, relatively high leverage and below-average financial and rate flexibility (for their rating category), as well as a heavy reliance on fossil fuel generation. Conversely, systems that show stable-to-improving financial metrics, limited new capital needs and a greener generation portfolio are expected to maintain stable outlooks, and in some cases may realize improved credit profiles.

Pipeline, Terminal and Midstream Sector

The short- and long-term outlook is stable for the natural gas and products pipelines in 2009, although a continuation of unfavorable capital market conditions, aggressive capital investment and recession could result in a moderate weakening of credit metrics.

The short- and long-term outlook for the natural gas gatherers is stable as well, reflecting the group's relatively predictable, primarily fee-based revenue stream, strong underlying demand growth and discretionary capital expenditures. Meanwhile, a weak economy and low energy commodity prices result in a negative short-term outlook for the natural gas processors; however, the stable long-term outlook is supported by manageable debt leverage, discretionary capital expenditures and expectations that NGL pricing will remain within historic norms experienced in 2005–2006.

The outlook for retail propane distributors remains negative as the result of declining volumes and the uncertain impact of consumer conservation in a lower natural gas price environment.

For further information, please refer to the "Pipeline/Midstream/MLP 2009 Outlook: Time for Companies to Play Defense" report, dated Nov. 20, 2008.

Appendix: Ratings and Rating Outlooks by Segment

Utility Parent Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Laclede Group, Inc.(The)	A+	Stable	A–
WGL Holdings, Inc.	A+	Stable	A+
FPL Group, Inc.	A	Stable	A
NICOR Inc.	A	Stable	A
OGE Energy Corp.	A	Stable	A
Sempra Energy	A	Stable	A
Southern Company	A	Stable	A
Southwest Power Pool	A	Stable	A
AGL Resources, Inc.	A–	Stable	A–
KeySpan Corporation	A–	Stable	A–
MDU Resources Group, Inc.	A–	Stable	A
National Fuel Gas Company	A–	Stable	A–
NSTAR	A–	Stable	A
SCANA Corporation	A–	Negative	A–
Wisconsin Energy Corporation	A–	Stable	A–
Ameren Corporation	BBB+	Stable	NR
Consolidated Edison, Inc.	BBB+	Stable	BBB+
Dominion Resources, Inc.	BBB+	Stable	BBB+
DPL Inc.	BBB+	Positive	BBB+
Exelon Corporation	BBB+	RWN	BBB+
MidAmerican Energy Holdings Co.	BBB+	Stable	BBB+
Public Service Enterprise Group Inc.	BBB+	Stable	BBB+
Xcel Energy Inc.	BBB+	Stable	BBB+
At Segment Median Rating			
American Electric Power Company	BBB	Stable	BBB
Black Hills Corp.	BBB	Stable	BBB
Constellation Energy Group, Inc.	BBB	RWE	BBB
DTE Energy Company	BBB	Negative	BBB
Energy East Corporation	BBB	Stable	BBB
FirstEnergy Corp.	BBB	Stable	BBB
IDACORP, Inc.	BBB	Negative	NR
NiSource Inc.	BBB	Stable	BBB
Northeast Utilities	BBB	Stable	BBB
PEPCO Holdings	BBB	Stable	BBB
PPL Corporation	BBB	Stable	BBB
Progress Energy, Inc	BBB	Stable	BBB
Below Segment Median Rating			
Allegheny Energy, Inc.	BBB–	Stable	NR
Centerpoint Energy Inc.	BBB–	Stable	BBB–
CILCORP, Inc.	BBB–	Stable	BBB–
Edison International	BBB–	Stable	NR
Entergy Corp.	BBB–	Evolving	NR
IPALCO Enterprises, Inc.	BBB–	Positive	BBB–
Pinnacle West Capital Corporation	BBB–	Negative	BBB–
TECO Energy, Inc.	BBB–	Stable	BBB–
Avista Corporation	BB+	Positive	BBB–
CMS Energy Corporation	BB+	Stable	BB+
PNM Resources	BB	Stable	BB
NV Energy, Inc.	BB–	Positive	BB–
Energy Future Holdings Corp.	B	Stable	B+

NR – Not rated. RWN – Rating Watch Negative. RWE – Rating Watch Evolving.
Source: Fitch.

Electric Distribution Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
NSTAR Electric Co.	A+	Stable	AA-
San Diego Gas & Electric Co.	A+	Stable	AA-
American Transmission Company	A	Stable	A+
Central Hudson Gas & Electric Corp.	A-	Stable	A
Orange & Rockland Utilities, Inc.	A-	Stable	A
Rockland Electric Co.	A-	Stable	NR
At Segment Median Rating			
Baltimore Gas and Electric Company	BBB+	RWE	A-
Consolidated Edison Co. of New York, Inc.	BBB+	Stable	A-
Delmarva Power & Light Company	BBB+	Stable	A-
PECO Energy Co.	BBB+	Stable	A
Potomac Electric Power Co.	BBB+	Stable	A-
Public Service Electric & Gas Co.	BBB+	Stable	A
Below Segment Median Rating			
Atlantic City Electric Company	BBB	Stable	BBB+
Centerpoint Energy Houston Electric, LLC	BBB	Stable	BBB
Connecticut Light and Power Co.	BBB	Stable	BBB+
Jersey Central Power & Light Co.	BBB	Stable	BBB+
New York State Electric & Gas Corp.	BBB	Negative	BBB+
PPL Electric Utilities Corporation	BBB	Stable	A-
Western Massachusetts Electric Co.	BBB	Stable	BBB+
Central Illinois Public Service Company	BBB-	Stable	BBB
Illinois Power Co.	BBB-	Stable	BBB
Metropolitan Edison Company	BBB-	Stable	BBB
Oncor Electric Delivery Company	BBB-	Stable	BBB-
Pennsylvania Electric Company	BBB-	Stable	BBB
Pennsylvania Power Company	BBB-	Stable	BBB+
Rochester Gas & Electric Corporation	BBB-	Stable	BBB
West Penn Power Co.	BBB-	Stable	BBB-
Commonwealth Edison Company	BB+	Stable	BBB-
Potomac Edison Co.	BB+	Negative	BBB-
Texas-New Mexico Power Company	BB+	Stable	BBB-

NR – Not rated. RWE – Rating Watch Evolving. Note: Bold indicates Senior Secured.
Source: Fitch.

Integrated Utility Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Mississippi Power Company	A+	Stable	AA–
Oklahoma Gas and Electric Company	A+	Stable	AA–
Alabama Power Company	A	Stable	A+
Florida Power & Light Co.	A	Stable	A+
Georgia Power Company	A	Stable	A+
Wisconsin Electric Power Co.	A	Stable	A+
Carolina Power & Light Company	A–	Stable	A
Dayton Power & Light Company	A–	Positive	A+
Florida Power Corporation	A–	Stable	A
Gulf Power Company	A–	Stable	A
MidAmerican Energy Company	A–	Stable	A
Northern States Power Co. (MN)	A–	Stable	A
Northern States Power Co. (WI)	A–	Stable	A
Pacific Gas & Electric	A–	Stable	A
South Carolina Electric & Gas Co.	A–	Negative	A
Southern California Edison Co.	A–	Stable	A
Union Electric Company	A–	Negative	A
AEP Texas North Co.	BBB+	Stable	A–
Columbus Southern Power Co.	BBB+	Stable	A–
Ohio Power Co.	BBB+	Stable	BBB+
Public Service Co. of Colorado	BBB+	Stable	A–
Virginia Electric & Power Co.	BBB+	Stable	A–
At Segment Median Rating			
AEP Texas Central Co.	BBB	Stable	BBB+
Appalachian Power Co.	BBB	Negative	BBB+
Black Hills Power, Inc.	BBB	Stable	BBB+
Central Illinois Light Co.	BBB	Stable	BBB+
Detroit Edison Co.	BBB	Stable	A–
Idaho Power Co.	BBB	Negative	BBB+
Northern Indiana Public Service Co.	BBB	Stable	BBB+
PacifiCorp	BBB	Stable	BBB+
Public Service Co. of New Hampshire	BBB	Stable	BBB+
Public Service Co. of Oklahoma	BBB	Stable	BBB+
Southwestern Electric Power Co.	BBB	Stable	BBB+
Southwestern Public Service Company	BBB	Stable	BBB+
Tampa Electric Company	BBB	Stable	BBB+
Below Segment Median Rating			
Arizona Public Service Co.	BBB–	Stable	BBB
Consumers Energy Co.	BBB–	Stable	BBB
Empire District Electric Company	BBB–	Negative	BBB
Entergy Arkansas Inc.	BBB–	Stable	BBB
Entergy Louisiana LLC	BBB–	Stable	BBB
Entergy Mississippi, Inc.	BBB–	Stable	BBB+
Indiana Michigan Power Company	BBB–	Stable	BBB
Indianapolis Power & Light Company	BBB–	Positive	BBB
Kansas Gas & Electric Company	BBB–	Stable	BBB+
Kentucky Power Co.	BBB–	Stable	BBB
Monongahela Power Company	BBB–	Stable	BBB–
Northwestern Corporation	BBB–	Positive	BBB–
Ohio Edison Co.	BBB–	Stable	BBB
System Energy Resources Inc.	BBB–	Stable	BBB–
Westar Energy	BBB–	Stable	BBB
Avista Corporation	BB+	Positive	BBB–
Cleveland Electric Illuminating Co.	BB+	Positive	BBB-
Entergy Gulf States, Inc.	BB+	Stable	BBB–
Entergy Texas, Inc.	BB+	Stable	NR
Toledo Edison Co.	BB+	Positive	BBB–
Entergy New Orleans, Inc.	BB	Positive	BBB–
Nevada Power Co.	BB	Positive	BB
Public Service Co. of New Mexico	BB	Stable	BB+
Sierra Pacific Power Company	BB	Positive	BBB–
Tucson Electric Power Co.	BB	Stable	BB+

NR – Not rated. Note: Bold indicates Senior Secured.
Source: Fitch.

Natural Gas Distribution Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Southern California Gas Co.	A+	Stable	AA–
Washington Gas Light Co.	A+	Stable	AA–
Brooklyn Union Gas Co.	A	Stable	A+
Nicor Gas Company	A	Stable	A+
Wisconsin Gas Company, LLC	A	Stable	A+
At Segment Median Rating			
Atlanta Gas Light Co.	A–	Stable	A
Cascade Natural Gas Corporation	A–	Stable	A
KeySpan Gas East Corp.	A–	Stable	A
Laclede Gas Company	A–	Stable	**A+**
NSTAR Gas	A–	Stable	**A**
Public Service Co. of North Carolina	A–	Negative	A
UGI Utilities Inc.	A–	Stable	A
Below Segment Median Rating			
Berkshire Gas Company	**BBB+**	Stable	A–
Central Maine Power Co.	**BBB+**	Stable	A–
Connecticut Natural Gas Corp.	**BBB+**	Stable	A–
Southern Connecticut Gas Co.	**BBB+**	Stable	A–
Atmos Energy Corp.	**BBB**	Stable	**BBB+**
Southwest Gas Corporation	**BBB**	Stable	**BBB**
Michigan Consolidated Gas Co.	BBB–	Stable	**BBB+**
Mountaineer Gas Company	BB–	Stable	BB

Note: Bold indicates Senior Secured.
Source: Fitch.

Pipeline, Midstream and Retail Propane Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Northern Natural Gas Company	A	Stable	A
Centennial Energy Holdings, Inc.	A–	Stable	A–
LOOP LLC	A–	Stable	A–
DCP Midstream LLC	BBB+	Stable	BBB+
Texas Eastern Transmission, LP	BBB+	Stable	BBB+
Texas Gas Transmission LLC	BBB+	Stable	BBB+
Boardwalk Pipelines, LLC	BBB	Stable	BBB
Centerpoint Energy Resources Corp.	BBB	Stable	BBB
Enogex Inc.	BBB	RWN	BBB
Kinder Morgan Energy Partners, LP	BBB	Stable	BBB
Northwest Pipeline Corp.	BBB	RWE	BBB
Panhandle Eastern Pipe Line Co.	BBB	Negative	BBB
Rockies Express Pipeline LLC	BBB	Stable	BBB
Transcontinental Gas Pipe Line Corp.	BBB	RWE	BBB
At Segment Median Rating			
Colorado Interstate Gas Co.	BBB–	Stable	BBB–
El Paso Natural Gas Co.	BBB–	Stable	BBB–
Energy Transfer Partners, L.P.	BBB–	Stable	BBB–
Enterprise Products Operating, L.P.	BBB–	Stable	BBB–
Kaneb Pipe Line Operating Partnership, L.P.	BBB–	Negative	BBB–
NGPL PipeCo LLC	BBB–	Stable	BBB–
Nustar Logistics Operations LP	BBB–	Negative	BBB–
Southern Natural Gas Co.	BBB–	Stable	BBB–
Southern Union Co.	BBB–	Stable	BBB–
Tennessee Gas Pipeline Co.	BBB–	Stable	BBB–
Teppco Partners, L.P.	BBB–	Stable	BBB–
Williams Companies, Inc.	BBB–	RWE	BBB–
Below Segment Median Rating			
AmeriGas Partners, L.P.	BB+	Stable	BB+
El Paso Corp.	BB+	Stable	BB+
El Paso Exploration & Production Co.	BB+	Stable	BB
Knight Inc.	BB+	Stable	BB+
Williams Partners, LP	BB+	Stable	BB+
Energy Transfer Equity, L.P.	BB–	Stable	BB
Enterprise GP Holdings L.P.	BB–	Stable	BB
Star Gas Partners L.P.	B	Stable	B+

NR– Not rated. RWN – Rating Watch Negative. RWE – Rating Watch Evolving. Note: Bold indicates Senior Secured.
Source: Fitch.

Competitive Generation Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Ameren Energy Generating Co.	BBB+	Stable	BBB+
Exelon Generation Co. LLC	BBB+	RWN	BBB+
PSEG Power LLC	BBB+	Stable	BBB+
Southern Power Co.	BBB+	Stable	BBB+
Black Hills Power	BBB	Stable	BBB+
PPL Energy Supply, LLC	BBB	Stable	BBB+
Allegheny Energy Supply Co., LLC	BBB–	Stable	BBB–
Allegheny Generating Co.	BBB–	Stable	BBB–
Brookfield Renewable Power, Inc.	BBB–	Stable	BBB
PSEG Energy Holdings LLC	BB+	Stable	BB
Midwest Generation, LLC	BB	Stable	BBB–
At Segment Median Rating			
Edison Mission Energy	BB–	Stable	BB–
Mission Energy Holding Co.	BB–	Stable	BB–
Below Segment Median Rating			
AES Corporation	B+	Stable	BB
Mirant Americas Generation, LLC	B+	Stable	B
Mirant Corp.	B+	Stable	NR
Mirant Mid-Atlantic LLC	B+	Stable	BB+
Mirant North America, LLC	B+	Stable	BB–
Dynegy Holdings, Inc.	B	Stable	B+
Dynegy Inc.	B	Stable	NR
NRG Energy, Inc.	B	RWE	B+
Reliant Energy, Inc.	B	Negative	B+
Texas Competitive Electric Holdings	B	Stable	B+

NR – Not rated. RWN – Rating Watch Negative. RWE – Rating Watch Evolving. Note: Bold indicates Senior Secured.
Source: Fitch.

Public Power Companies

Company Name	Rating Outlook	Senior Rating
Retail Segment — Above Median (A+)		
Chelan County Public Utility District No. 1 (Wash.)	Stable	AA+
San Antonio (Texas) (CPS Energy)	Stable	AA+
Chattanooga — Electric Power Board (Tenn.)	Stable	AA
Grant County Public Utility District No. 2 (Wash.) — Electric System	Stable	AA
Lincoln (Neb.) — Electric System	Stable	AA
Memphis (Tenn.) — Memphis Light, Gas & Water	Stable	AA
Nashville (Tenn.) — Electric System	Stable	AA
Omaha Public Power District (Neb.)	Stable	AA
Orlando Utilities Commission (Fla.)	Stable	AA
Springfield (Mo.) — City Utilities (Electric)	Stable	AA
St. Cloud (Fla.) — Utility System	Stable	AA
Anaheim Public Utilities Department (Calif.)	Stable	AA–
Austin Energy (Texas)	Stable	AA–
Hydro-Quebec	Positive	AA–
Imperial Irrigation District (Calif.)	Negative	AA–
JEA (Fla.) — Electric	Stable	AA–
Los Angeles Department of Water and Power (Calif.)	Stable	AA–
New Braunfels Utilities (Texas)	Stable	AA–
Pasadena (Calif.) — Water and Power Department	Stable	AA–
Pedernales Electric Cooperative, Inc. (Texas)	Stable	AA–
Riverside Public Utilities (Calif.)	Stable	AA–
Rochester Public Utilities (Minn.)	Stable	AA–
Tallahassee (Fla.) — Energy System	Stable	AA–
Retail Segment — At Median Rating		
Anchorage Municipal Light & Power (Alaska)	Stable	A+
Bryan, Texas Utilities	Stable	A+
California Department of Water Resources	Positive	A+
Dover (Del.)	Stable	A+
Eugene Water and Electric Board (Ore.)	Stable	A+
Farmington (N.M.) Utility System	Stable	A+
Garland Power & Light (Texas)	Stable	A+
Glendale (Calif.) — Water and Power	Stable	A+
Kansas City (Kan.) — Board of Public Utilities	Stable	A+
Kerrville Public Utility Board (Texas)	Stable	A+
Lakeland Energy System (Fla.)	Stable	A+
Modesto Irrigation District (Calif.)	Stable	A+
Muscatine Power & Water (Iowa)	Stable	A+
Roseville Electric System (Calif.)	Stable	A+
Snohomish County Public Utility District No. 1 (Wash.)	Stable	A+
Tacoma Power (Wash.)	Stable	A+
Turlock Irrigation District (Calif.)	Stable	A+
Retail Segment — Below Median Rating		
Benton County Public Utility District No. 1 (Wash.)	Stable	A
Brownsville Public Utility Board (Texas)	Stable	A
Bryan, Rural Electric	Stable	A
Floresville (Texas) — Electric Light and Power System	Stable	A
Gallup (N.M.) — Utility System	Stable	A
Grays Harbor County Public Utility District No. 1 (Wash.)	Stable	A
Kissimmee Utility Authority (Fla.)	Stable	A
Overton Power District No. 5 (NV)	Stable	A
Sacramento Municipal Utility District (Calif.)	Stable	A
Silicon Valley Power (Calif.)	Stable	A
Vero Beach (Fla.)	Stable	A
Winter Park (Fla.)	Stable	A

Note: Public power entities are not assigned issuer default ratings. *Continued on next page.*
Source: Fitch.

Public Power Companies (Continued)

Company Name	Rating Outlook	Senior Rating
Retail Segment — Below Median Rating (Continued)		
Alameda Power & Telecom (Calif.)	Stable	A–
Batavia (Ill.) — Electric Utility	Stable	A–
Boerne Utility System (Texas)	Stable	A–
Chugach Electric Association, Inc. (Alaska)	Stable	A–
Cowlitz CO Public Utility District	Stable	A–
Fort Pierce Utilities (Fla.)	Stable	A–
Long Island Power Authority (N.Y.)	Negative	A–
Los Alamos County (N.M.) — Utility System	Stable	A–
Pend Oreille County Public Utility District No. 1 (Wash.)	Stable	A–
Reedy Creek Improvement District (Fla.)	Stable	A–
Puerto Rico Electric Power Authority	Stable	A–
Seguin (Texas)	Stable	A–
Boise Kuna Irrigation District (ID)	Stable	BBB+
Leesburg (Fla.) — Electric System	Stable	BBB+
Lodi (Calif.) — Electric Utility	Positive	BBB+
Lubbock Power & Light (Texas)	Stable	BBB+
Virgin Islands Water & Power Authority	Stable	BBB
Vermont Electric Cooperative Inc.	Stable	BBB–
Guam Power Authority	Positive	BB+
Wholesale Segment — Above Median (A)		
Tennessee Valley Authority	Stable	AAA
Associated Electric Cooperative Inc. (MO)	Stable	AA
Grant County Public Utility District No. 2 (Wash.) — Hydro Projects	Stable	AA
New York Power Authority	Stable	AA
Platte River Power Authority (Colo.)	Stable	AA
South Carolina Public Service Authority (Santee Cooper)	Stable	AA
Basin Electric Power Cooperative	Stable	AA–
Energy Northwest (Wash) — Bonneville Power Agency	Positive	AA–
Intermountain Power Agency (Utah)	Stable	AA–
Western Minnesota Municipal Power Agency	Stable	AA–
Arkansas Electric Cooperative Corp.	Stable	A+
Buckeye Power, Inc. (Ohio)	Stable	A+
Connecticut Municipal Electric Energy Cooperative	Stable	A+
Florida Municipal Power Authority — All Requirements Project	Stable	A+
Florida Municipal Power Authority — Stanton I	Stable	A+
Florida Municipal Power Authority — Stanton II	Stable	A+
Florida Municipal Power Authority — Tri-City Project	Stable	A+
Illinois Municipal Electric Agency	Stable	A+
Indiana Municipal Power Agency	Stable	A+
Lower Colorado River Authority (Texas)	Stable	A+
M-S-R Public Power Agency (Calif.)	Stable	A+
Municipal Electric Authority of Georgia (CC/CT Proj)	Stable	A+
Municipal Electric Authority of Georgia (General Res)	Stable	A+
Municipal Electric Authority of Georgia (Project One)	Stable	A+
Municipal Electric Authority of Georgia (Telecom)	Stable	A+
Nebraska Public Power District	Stable	A+
Walnut Energy Center Authority (Calif.)	Stable	A+
Wisconsin Public Power Inc.	Stable	A+
Wholesale Segment — At Median Rating		
American Municipal Power-OH Underlying Rating	Stable	A
American Municipal Power-Inc. — Joint Venture No. 5	Stable	A
AMP-Ohio's Prairie State Project	Stable	A
Brazos Electric Power Cooperative, Inc. (Texas)	Stable	A
Florida Municipal Power Authority — St. Lucie Project	Stable	A
Grand River Dam Authority (Okla.)	Stable	A

Note: Public power entities are not assigned issuer default ratings. *Continued on next page.*
Source: Fitch.

Public Power Companies (Continued)

Company Name	Rating Outlook	Senior Rating
Wholesale Segment — At Median Rating (Continued)		
Massachusetts Municipal Wholesale Elec Co. (Nuclear Mix No. 1)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 3)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 4)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 5)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 6)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Stoney Brook Intermediate)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Wyman)	Stable	A
Missouri Joint Municipal Electric Utility Commission (Iatan 2 Project)	Stable	A
Municipal Energy Agency of Nebraska	Stable	A
North Carolina Municipal Power Agency No. 1	Stable	A
Northern California Power Authority — Geothermal Project	Stable	A
Northern California Power Authority — Hydroelectric Project	Stable	A
Oglethorpe Power Co. (Ga.)	Stable	A
Oglethorpe Power Co. (Ga.) — Scherer Facilities	Stable	A
Old Dominion Electric Cooperative (Va.)	Stable	A
Texas Municipal Power Agency	Stable	A
Tri-State Generation & Transmission Association, Inc. (Colo.)	Stable	A
Wholesale Segment — Below Median Rating		
American Municipal Power-Inc. — Joint Venture No. 2	Stable	A–
Central Iowa Power Cooperative	Stable	A–
Delaware Municipal Electric Cooperative	Stable	A–
Energy Northwest (Wash.) — Wind Project	Stable	A–
Golden Spread Electric Cooperative, Inc. (Texas)	Stable	A–
Great River Energy (Minn.)	Stable	A–
Missouri Joint Municipal Electric Utility Commission (Plum Point Project)	Stable	A–
Missouri Joint Municipal Electric Utility Commission (Prairie State Project)	Stable	A–
Northern Illinois Municipal Power Agency	Stable	A–
South Texas Electric Cooperative	Stable	A–
Western Farmers Electric Cooperative (Okla.)	Stable	A–
Central Valley Financing Authority (Calif.)	Stable	BBB+
North Carolina Eastern Municipal Power Agency	Stable	BBB+
Piedmont Municipal Power Agency (S.C.)	Stable	BBB+
PowerSouth Energy Cooperative, Inc. (f/k/a Alabama Elec Coop)	Stable	BBB+
Sacramento Cogeneration Authority (Calif.) — PG&E Project	Stable	BBB+
Sacramento Power Authority (Calif.) — Campbell Project	Stable	BBB+
Sacramento Municipal Utility District Financing Authority (Calif.) — Cosumnes Project	Positive	BBB
Sam Rayburn Municipal Power Agency (Texas)	Stable	BBB–
Combined Electric and Water Utility Systems		
Colorado Springs Utilities	Stable	AA
Austin Combined Utility System (Texas)	Stable	AA–
Concord (N.C.) Utilities System	Stable	AA–
Greer (S.C.) — Commission of Public Works	Stable	A+
Jacksonville Beach (Fla.) — Combined Utility System	Stable	A+
Ocala (Fla.)	Stable	A+
Other		
Florida Gas Utility	Stable	AA
JEA (Fla.) — Water & Sewer	Stable	AA
Omaha Metropolitan Utilities District (Neb.)	Stable	AA
Springfield (Mo.) — City Utilities (Water)	Stable	AA
American Municipal Power-Ohio, Inc. Purchase Revs	RWN	AA–
Austin Water and Wastewater System (Texas)	Stable	AA–
Central Plains Energy Project (Neb.), Project No. 1	Stable	AA–
Georgia Transmission Corporation	Stable	AA–
Indiana Bond Bank Special Program	Stable	AA–
Main Street Natural Gas, Inc. (Ga.) (Series 2006A)	Stable	AA–

RWN – Rating Watch Negative. Note: Public power entities are not assigned issuer default ratings. *Continued on next page.*
Source: Fitch.

Public Power Companies (Continued)

Company Name	Rating Outlook	Senior Rating
Other (Continued)		
Municipal Energy Acquisition Agency Corp. (TN)	Stable	AA–
Richmond (Va.)	Stable	AA–
SA Energy Acquisition Public Facility Corporation	Stable	AA–
Southern California Public Power Authority (SCPPA) Mead Adelanto Project	Stable	AA–
Southern California Public Power Authority (SCPPA) Mead Phoenix Project	Stable	AA–
Tennessee Energy Acquisition Corporation (Series 2006A)	Stable	AA–
Tennessee Energy Acquisition Corporation (Series 2006C)	Stable	AA–
Long Beach Bond Finance Authority Prepay	RWE	A+
Long Beach Gas Utility (Calif.)	Positive	A+
Lower Colorado River Authority (Texas) — Transmission Services Corp.	Stable	A+
Main Street Natural Gas, Inc. (Ga.) (Series 2006B)	RWE	A+
Main Street Natural Gas, Inc. (Ga.) (Series 2007A)	RWE	A+
Main Street Natural Gas, Inc. (Ga.) (Series 2008A)	Negative	A+
Municipal Gas Authority of Georgia (Agency)	Stable	A+
Municipal Gas Authority of Georgia (Gas Portfolio)	Stable	A+
Public Authority for Colorado Energy (CSU Prepay)	RWE	A+
Public Gas Partners (GA) Pool 2	Stable	A+
Roseville Natural Gas Finance Authority (Calif.)	RWE	A+
Transmission Agency of Northern California	Stable	A+
Indianapolis Thermal Energy System (Ind.)	Stable	A
National Rural Utilities Cooperative Finance Corp. (Va.)	Positive	A
Natural Gas Acquisition Corp. (Clarksville, TN)	RWE	A
Northern California Gas Authority No. 1	Stable	A
Public Gas Partners (GA) Pool 1	Stable	A
Southern California Public Power Authority — Natural Gas Project	Stable	A
Southmost Regional Water Authority (Brownsville, Texas)	Stable	A
Philadelphia (Pa.) — Gas Works	Stable	BBB

RWE – Rating Watch Evolving. Note: Public power entities are not assigned issuer default ratings. *Continued on next page.*
Source: Fitch.

Rating Methodology

Moody's Global Infrastructure Finance

August 2009

Regulated Electric and Gas Utilities

Table of Contents:

Analyst Contacts:

New York 1.212.553.1653

Michael G. Haggarty
Vice President - Senior Credit Officer

Mitchell Moss
Associate Analyst

W. Larry Hess
Team Managing Director

Thomas Keller
Group Managing Director

Bart Oosterveld
Chief Credit Officer, Public, Project & Infrastructure Finance

(Continued on back page)

Summary

This rating methodology provides guidance on Moody's approach to assigning credit ratings to electric and gas utility companies worldwide whose credit profile is influenced to a large degree by the presence of regulation. It replaces the Global Regulated Electric Utilities methodology published in March 2005 and the North American Regulated Gas Distribution Industry (Local Distribution Companies) methodology published in October 2006. While reflecting similar core principles as these previous methodologies, this updated framework incorporates refinements that better reflect the changing dynamics of the regulated electric and gas industry and the way Moody's applies its industry methodologies.

The goal of this rating methodology is to assist investors, issuers, and other interested parties in understanding how Moody's arrives at company-specific ratings, what factors we consider most important for this sector, and how these factors map to specific rating outcomes. Our objective is for users of this methodology to be able to estimate a company's ratings (senior unsecured ratings for investment-grade issuers and Corporate Family Ratings for speculative-grade issuers) within two alpha-numeric rating notches.

Regulated electric and gas companies are a diverse universe in terms of business model (ranging from vertically integrated to unbundled generation, transmission and/or distribution entities) and regulatory environment (ranging from stable and predictable regulatory regimes to those that are less developed or undergoing significant change). In seeking to differentiate credit risk among the companies in this sector, Moody's analysis focuses on four key rating factors that are central to the assignment of ratings for companies in the sector. The four key rating factors encompass nine specific elements (or sub-factors), each of which map to specific letter ratings (see Appendix A). The four factors are as follows:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

This methodology pertains to regulated electric and gas utilities and excludes regulated electric and gas networks (companies primarily engaged in the transmission and/or distribution of electricity and/or natural gas that do not serve retail customers) and unregulated utilities and power companies, which are covered by separate rating methodologies. Municipal utilities and electric cooperatives are also excluded and covered by separate rating methodologies.

In Appendix A of this methodology, we have included a detailed rating grid for the companies covered by the methodology. For each company, the grid maps each of these key rating factors and shows an indicated alpha-numeric rating based on the results from the overall combination of the factors (see Appendix B). We note, however, that many companies will not match each dimension of the analytical framework laid out in the rating grid exactly and that from time to time a company's performance on a particular rating factor may fall outside the expected range for a company at its rating level. These companies are categorized as "outliers" for that rating factor. We discuss some of the reasons for these outliers in this methodology as well as in published credit opinions and other company-specific analysis.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector. The grid provides summarized guidance on the factors that are generally most important in assigning ratings to the sector. While the factors and sub-factors within the grid are designed to capture the fundamental rating drivers for the sector, this grid does not include every rating consideration and does not fit every business model equally. Therefore, we outline additional considerations that may be appropriate to apply in addition to the four rating factors. Moody's also assesses other rating factors that are common across all industries, such as event risk, off-balance sheet risk, legal structure, corporate governance, and management experience and credibility. Furthermore, most of our sub-factor mapping uses historical financial results to illustrate the grid while our ratings also consider forward looking expectations. As such, the grid-indicated rating is not expected to always match the actual rating of each company. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this methodology does not attempt to provide an exhaustive list of every factor that can be relevant to a utility's ratings. For example, our analysis covers factors that are common across all industries (such as coverage metrics, debt leverage, and liquidity) as well as factors that can be meaningful on a company or industry specific basis (such as regulation, capital expenditure needs, or carbon exposure).

This publication includes the following sections:

- **About the Rated Universe**: An overview of the regulated electric and gas industries
- **About the Rating Methodology**: A description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

In the appendices, we also provide tables that illustrate the application of the methodology grid to 30 representative electric and gas utility companies with explanatory comments on some of the more significant differences between the grid-implied rating and our actual rating (Appendix C). We also provide definitions of key ratios (Appendix D), an industry overview (Appendix E) and a discussion of the key issues facing the industry over the intermediate term (Appendix F) and regional considerations (Appendix G).

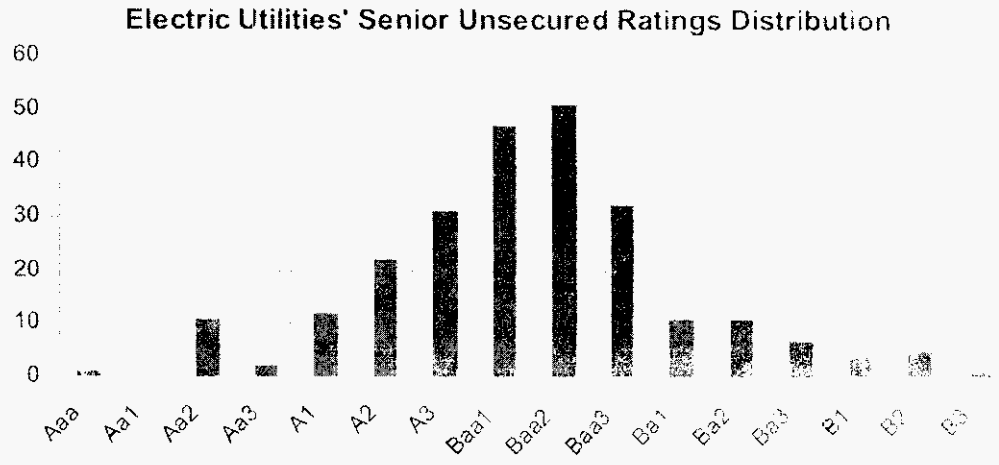
About the Rated Universe

The rating methodology covers investor-owned and commercially oriented government owned companies worldwide that are engaged in the production, transmission, distribution and/or sale of electricity and/or natural gas. It covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution companies, some U.S. transmission-only companies, and local gas distribution companies (LDCs). For the LDCs, we note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas companies that have significant non-utility

businesses[1]. In addition, this methodology includes both holding companies as well as operating companies. For holding companies, actual ratings may be lower than methodology grid-implied ratings due to the structural subordination of the holding company debt to the operating company debt. In order for a utility to be covered by this methodology, the company must be an investor-owned or commercially oriented government owned entity and be subject to some degree of government regulation or oversight. This methodology excludes regulated electric and gas networks, electric generating companies[2] and independent power producers operating predominantly in unregulated power markets, municipally owned utilities, electric cooperative utilities, and power projects, which are covered in separate rating methodologies.

The rated universe includes approximately 250 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. They account for about US$650 billion of total outstanding long-term debt instruments. In general, ratings used in this methodology are the Senior Unsecured ("SU") rating for investment grade companies, the Corporate Family Rating ("CFR") for non-investment grade companies, and the Baseline Credit Assessment ("BCA") for Government Related Issuers (GRI). A subset of 30 of these entities is included in the methodology, representing a sampling of the universe to which this methodology applies.

Geographically, this methodology covers companies in the Americas, Europe, Middle East, Africa, Japan, and the Asia/Pacific region. The ratings spectrum for the sector ranges from Aaa to B3, with the actual rating distribution of the issuers included (both holding companies and operating companies) shown on the following table:



Although all of these companies are affected to some degree by government regulation or oversight, country-by-country regulatory differences and cultural and economic characteristics are also important credit considerations. There is little consistency in the approach and application of regulatory frameworks around the world. Some regulatory frameworks are highly supportive of the utilities in their jurisdictions, in some cases offering implied sovereign support to ensure reliability of electric supply. Other regulatory frameworks are less supportive, more unpredictable or affected by political influence that can increase uncertainty and negatively affect overall credit quality.

[1] These companies are assessed under the rating methodology "North American Diversified Natural Gas Transmission and Distribution Companies", March 2007.

[2] The six Korean generation companies are included in this methodology as they are subject to regulation and Moody's views them and their 100% parent and sole off-taker KEPCO on a consolidated basis. The Brazilian generation companies are included as they are also subject to regulatory intervention.

About this Rating Methodology

Moody's approach to rating companies in the regulated electric and gas utility sector, as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

In general, Moody's rating committees for the regulated electric and gas utility sector focus on a number of key rating factors which we identify and quantify in this methodology. A change in one or more of these factors, depending on its weighting, is likely to influence a utility's overall business and financial risk. We have identified the following four key rating factors and nine sub-factors when assigning ratings to regulated electric and gas utility issuers:

Rating Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%		25%
Ability to Recover Costs and Earn Returns	25%		25%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Liquidity and Key Financial Metrics	40%	Liquidity	10%
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	7.5%
		CFO pre-WC - Dividends / Debt	7.5%
		Debt/Capitalization or Debt / Regulated Asset Value	7.5%
Total	100%		100%

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

These factors are critical to the analysis of regulated electric and gas utilities and, in most cases, can be benchmarked across the industry. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2. Measurement of the Key Rating Factors

We next explain the elements we consider and the metrics we use to measure relative performance on each of the four factors. Some of these measures are quantitative in nature and can be specifically defined. However, for other factors, qualitative judgment or observation is necessary to determine the appropriate rating category.

Moody's ratings are forward looking and attempt to rate through the industry's characteristic volatility, which can be caused by weather variations, fuel or commodity price changes, cost deferrals, or reasonable delays in regulatory recovery. The rating process also makes extensive use of historic financial statements. Historic results help us understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes. All financial measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts for (among other things) underfunded pension obligations and operating leases.

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match the performance of each factor and sub-factor to one of Moody's broad rating categories (Aaa, Aa, A, Baa, Ba, and B). In this report, we provide a

range or description for each of the measurement criteria. For example, we specify what level of CFO pre-WC plus Interest/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

For each factor and sub-factor, we provide a table showing how a subset of the companies covered by the methodology maps within the specific factors and sub-factors. We recognize that any given company may perform higher or lower on a given factor than its actual rating level will otherwise indicate. These companies are identified as "outliers" for that factor. A company whose performance is two or more broad rating categories higher than its rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers for each factor.

5. Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall rating, each of the factors and sub-factors is converted into a numeric value based on the following scale:

Ratings Scale

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

Each sub-factor's numeric value is multiplied by an assigned weight and then summed to produce a composite weighted-average score. The total sum of the factors is then mapped to the ranges specified in the table below, and the indicated alpha-numeric rating is determined based on where the total score falls within the ranges.

Factor Numerics

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	< 1.5
Aa1	1.5 < 2.5
Aa2	2.5 < 3.5
Aa3	3.5 < 4.5
A1	4.5 < 5.5
A2	5.5 < 6.5
A3	6.5 < 7.5
Baa1	7.5 < 8.5
Baa2	8.5 < 9.5
Baa3	9.5 < 10.5
Ba1	10.5 < 11.5
Ba2	11.5 < 12.5
Ba3	12.5 < 13.5
B1	13.5 < 14.5
B2	14.5 < 15.5
B3	15.5 < 16.5

For example, an issuer with a composite weighting factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the four broad rating categories.

The Key Rating Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Rating Factor 1: Regulatory Framework (25%)

Why it Matters

For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. The latter is largely addressed in Factor 2, Ability to Recover Cost and Earn Returns, discussed below. However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions.

How We Measure It for the Grid

For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor. Consideration is given to the substance of any regulatory ring fencing provisions, including restrictions on dividends; restrictions on capital expenditures and investments; separate financing provisions; separate legal structures; and limits on the ability of the regulated entity to support its parent company in times of financial distress. The criteria for each rating category are outlined in the factor description within the rating grid.

For regulated electric utilities with some unregulated operations, consideration will be given to the competitive and business position of these unregulated operations[3]. Moody's views unregulated operations that have minimal or limited competition, large market shares, and statutorily protected monopoly positions as having substantially less risk than those with smaller market shares or in highly competitive environments. Those businesses with the latter characteristics usually face a higher likelihood of losing customers, revenues, or market share. For electric utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be if the utility had solely regulated operations.

Moody's views the regulatory risk of U.S. utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia, and Canada The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the U.S. results in stronger competition in wholesale power markets; U.S. fuel and power markets are more

[3] For diversified gas companies, the "North American Diversified Natural Gas Transmission and Distribution Company" rating methodology is applied.

volatile; there is a low likelihood of extraordinary political action to support a failing company in the U.S.; holding company structures limit regulatory oversight; and overlapping or unclear regulatory jurisdictions characterize the U.S. market. As a result, no U.S. utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor.

The scores for this factor replace the classifications we had been using to assess a utility's regulatory framework, namely, the Supportiveness of Regulatory Environment (SRE) framework, outlined in our previous rating methodology (Global Regulated Electric Utilities, March 2005), which we are phasing out. Generally speaking, an SRE 1 score from our previous methodology would roughly equate to Aaa or Aa ratings in this methodology; an SRE 2 score to A or high Baa; an SRE 3 score to low Baa or Ba, and an SRE 4 score to a B. For U.S. and Canadian LDCs, this factor corresponds to the "Regulatory Support" and "Ring-fencing" factors in our previous methodology (North American Regulated Gas Distribution, October 2006).

Factor 1 – Regulatory Framework (25%)

Aaa	Aa	A	Baa	Ba	B
Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.

Rating Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

Unlike Factor 1, which considers the general regulatory framework under which a utility operates and the overall business position of a utility within that regulatory framework, this factor addresses in a more specific manner the ability of an individual utility to recover its costs and earn a return. The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. The reluctance to provide rate relief reflected regulatory commission concerns about the impact of large rate increases on customers as well as debate about the appropriateness of the relief being sought by the utility and views of imprudency. Currently, the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed.

How We Measure It for the Grid

For regulated utilities, the criteria we consider include the statutory protections that are in place to insure full and timely recovery of prudently incurred costs. In its strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to

rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan, for example, where the utilities in that country receive a score of Aa for this factor.

More typically, however, and as is characteristic of most utilities in the U.S., the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost recovery or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score of A for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa rating for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

For regulated electric utilities that have some unregulated operations, we assess the likelihood that the utility will be able to pass on costs of its unregulated businesses to unregulated customers. Among the criteria we use to judge this factor include the number and types of different businesses the company is in; its market share in these businesses; whether there are significant barriers to entry for new competitors; and the degree to which the utility is vertically integrated. Those utilities with several businesses with large market shares are generally in a better position to pass on their costs to unregulated customers. Those utilities that have lower market shares in their unregulated activities or are in businesses with few barriers to entry will likely be more at risk in passing on costs, and thus would receive lower scores. A high proportion of unregulated businesses or a higher risk of passing on costs to unregulated customers could result in a lower score for this factor than would apply if the business was completely regulated.

For U.S. and Canadian LDCs, this factor addresses the "Sustainable Profitability" and "Regulatory Support" assessments in the previous LDC rating methodology. While LDCs' authorized returns are comparable to those for their electric counterparts, the smaller, more mature LDCs tend to face less regulatory challenges. Purchased Gas Adjustment mechanisms are the norm and they have made strides in implementing alternative rate designs that decouple revenues from volumes sold.

Factor 2 – Ability to Recover Costs and Earn Returns (25%)

Aaa	Aa	A	Baa	Ba	B
Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.

Rating Factor 3 - Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that any one part of the company will have a severe negative impact on cash flow and credit quality. In general, a balance among several different businesses, geographic regions, regulatory regimes, generating plants, or fuel sources will diminish concentration risk and reduce the risk that a company will experience a sudden or rapid deterioration in its overall creditworthiness because of an adverse development specific to any one part of its operations.

How We Measure It For the Grid

For transmission and distribution utilities, local gas distribution companies, and other companies without significant generation, the key criterion we use is the diversity of their operations among various markets, geographic regions or regulatory regimes. For these utilities, the first set of criteria, labeled market diversification, account for the full 10% weighting for this factor. A predominately T&D utility with a high degree of diversification in terms of market and/or regulatory regime is less likely to be affected by adverse or unexpected developments in any one of these markets or regimes, and thus will receive the highest scores for this factor. Smaller T&D utilities operating in a limited market area or under the jurisdiction of a single regulatory regime will score lower on the factor, with those that are concentrated in an emerging market or riskier environment receiving the lowest scores.

For vertically integrated utilities with generation, the diversification factor is broadened to include not only the criteria discussed above, but also takes into consideration the diversity of their generating assets and the type of fuel sources which they rely on. An additional but somewhat related consideration is the degree to which the utility is exposed to (or insulated from) commodity price changes. A utility with a highly diversified fleet of generating assets using different types of fuels is generally better able to withstand changes in the price of a particular fuel or additional costs required for particular assets, such as more stringent environmental compliance requirements, and thus would receive a higher rating for this sub-factor. Those utilities with more limited diversification or that are more reliant on a single type of generation and fuel source (measured by energy produced) will be scored lower on this sub-factor. Similarly, those utilities with a high reliance on coal and other carbon emitting generating resources will be scored lower on this factor due to their vulnerability to potential carbon regulations and accompanying carbon costs.

Generally, only the largest vertically integrated utilities or transmission companies with substantial operations that are multinational or national in scope, or whose operations encompass a substantial region within a single country, will receive scores in the highest Aaa or Aa categories for this factor. In the U.S., most of the largest multi-state or multi-regional utilities are scored in the A category, most of the larger single state utilities are scored Baa, and smaller utilities operating in a single state or within a single city are scored Ba. A utility may also be scored higher if it is a combination electric and gas utility, which enhances diversification.

The diversification factor was not included in the previous North American LDC methodology. Most LDCs are small and tend to have little geographic and regulatory diversity. However, they tend to be highly stable due to their customer base and margins that comprise primarily of a large number of residential and small commercial customers that are captive to the utility. This customer composition tends to result in a more stable operating performance than those that have concentrations in certain industrial customers that are prone to cyclicality or to bypassing the LDC to obtain gas directly from a pipeline. Pure LDCs are scored under the "Market Position" sub-factor for a full 100% under this factor. As with transmission and distribution utilities, no scores are given for "Fuel/Generation Diversification" as this sub-factor would not be applicable.

Factor 3: Diversification (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/ regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation **0% weight for issuers that lack generation*

Rating Factor 4 – Financial Strength and Liquidity (40%)

Why It Matters

Since most electric and gas utilities are highly capital intensive, financial strength and liquidity are key credit factors supporting their long-term viability. Financial strength and liquidity are also important to the maintenance of good relationships with regulators, to assure adequate regulatory responsiveness to rate increase requests and for cost recovery, and to avoid the need for sudden or unexpected rate increases to avoid financial problems. Financial strength is also important due to the ongoing need to invest in generation, transmission, and distribution assets that often require substantial amounts of debt financing. Utilities are among the largest debt issuers in the world and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility.

Although ratio analysis is a helpful way of comparing one company's performance to that of another, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. The relative strength of a company's financial ratios must take into consideration the level of business risk associated with the more qualitative factors in the methodology. *Companies with a lower business risk can have weaker credit metrics than those with higher business risk for the same rating category.*

Given the long-term nature of many of the capital intensive projects undertaken in the industry and the need to obtain regulatory recovery over an often multi-year time period, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from the historic measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance.

How We Measure It For the Grid

In addition to assigning a score for a utility's overall liquidity position and relative access to funding sources and the capital markets, we have identified four key core ratios that we consider the most useful in the analysis of regulated electric and gas utilities. The four ratios are the following:

- Cash from Operations (CFO) pre-Working Capital Plus Interest / Interest
- Cash from Operations (CFO) pre-Working Capital / Debt
- Cash from Operations (CFO) pre-Working Capital – Dividends / Debt
- Debt/Capitalization or Debt / Regulated Asset Value (RAV)

The use of Debt / Capitalization or Debt / Regulated Asset Value will depend largely on the regulatory regime in which the utility operates, as explained below. These credit metrics incorporate all of the standard adjustments applied by Moody's when analyzing financial statements, including adjustments for certain types of off-balance sheet financings and certain other reclassifications in the income statement and cash flow statement.

These cash flow based ratios replace the earnings based metrics in the previous "North American Local Gas Distribution Company" rating methodology, reducing the impact on the grid results from non-cash items, such as pension expense.

The ratio calculations utilized and published for the companies covered by this methodology (including the 30 representative electric and gas utility companies highlighted) are historical three-year averages for the years 2006-2008. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios.

Measurement Criteria

Liquidity

Liquidity analysis is a key element in the financial analysis of electric and gas utilities and encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources. Sources of funds are compared to a company's cash needs and other obligations over the next twelve months. The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those utilities that are financially robust under all or virtually all scenarios, with little to no need for external funding and with unquestioned or superior access to the capital markets. Most utilities, however, receive more moderate scores of between "A" and "Baa" in this sub-factor as most need to rely to some degree on external funding sources to finance capital expenditures and meet other capital needs. Below investment grade scores on the sub-factor are assigned to utilities with weak liquidity or those that rely heavily on debt to finance investments.

CFO pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is a basic measure of a utility's ability to cover the cost of its borrowed capital and is an important analytical tool in this highly capital intensive industry. The numerator in the ratio calculation is a measure of cash flow excluding working capital movements plus interest expense, which can vary in significance depending on the utility. The use of CFO pre-WC is more comprehensive than Funds from Operations (FFO) under U.S. Generally Accepted Accounting Principles (GAAP) since it also captures the changes in long-term regulatory assets and liabilities. However, under International Financial Reporting Standards (IFRS), the two measures are essentially the same. The denominator in the ratio calculation is interest expense, which incorporates our standard adjustments to interest expense, such as including

capitalized interest and re-classifying the interest component of operating lease rental expense. In Brazil, the cash interest amount is adjusted by the variation of non-cash financial expenses derived from foreign exchange and inflation denominated debt.

CFO pre-Working Capital / Debt

This metric measures the cash generating ability of a utility compared to the aggregate level of debt on the balance sheet. This ratio is useful in comparing utilities, many of which maintain a significant amount of leverage in their capital structure. The debt calculation takes into consideration Moody's standard adjustments to balance sheet debt, such as for operating leases, underfunded pension liabilities, basket-adjusted hybrids, guarantees, and other debt-like items.

CFO pre-Working Capital – Dividends / Debt

This ratio is a measure of financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial and can affect the ability of a utility to cover its debt obligations. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. Moody's expects that even the financially strongest utilities will need to issue debt on a regular basis to maintain a target capital structure if their asset bases are growing. If a utility with an expanding asset base funds all of its capital expenditures with internally generated cash flow then, in the extreme, the utility's debt to capitalization will trend toward zero.

Debt/Capitalization or Debt/Regulated Asset Value or RAV

This ratio is a traditional measure of leverage and can be a useful way to gauge a utility's overall financial flexibility in light of its overall debt load. High debt to capitalization levels are not only an indicator of higher interest obligations, but can also limit the ability of a utility to raise additional financing if needed and can lead to leverage covenant violations in bank credit facilities or other financing agreements. The denominator of the debt / capitalization ratio includes Moody's standard adjustments, the most important of which for some utilities is the inclusion of deferred taxes in capitalization, which tempers the impact of our debt adjustment.

While debt/capitalization is used predominantly in the Americas, other regions may use a variation of this ratio, namely, debt/regulated asset value or RAV ratio. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services and the RAV represents the value on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules (i.e. Australia and Japan), debt/RAV is viewed as superior to debt / capitalization as a credit measure and will be used for this sub-factor. Where RAV does not exist (i.e. North America and most Asian countries) or the method of calculation is subject to arbitrary or unpredictable revisions, we use debt/capitalization.

Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)							
	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Rating Methodology Assumptions and Limitations, and other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The four rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be impacted by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, and other factors. In either case, we acknowledge that estimating future performance is subject to the risk of substantial inaccuracy.

In choosing metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance, financial controls, and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, financial controls, and emerging market risk, where ratings might be

constrained by the uncertainties associated with the local operating, political and economic environment, including possible government interference.

Actual assigned ratings may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, although Factors 1 and 2 address regulation and cost recovery, in some instances the effect of a company's financial strength and liquidity in Factor 4 will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 30 representative utilities highlighted, the methodology grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

- 30% or 9 companies map to their assigned rating
- 50% or 15 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating
- 20% or 6 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

Grid-Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch	Map to Within Two Notches
American Electric Power Company, Inc.	Cemig Distribuicao S.A.	Duke Energy Corporation
Arizona Public Service Company	Consolidated Edison Company of New York	Eesti Energia AS
CLP Holdings Limited	Dominion Resources, Inc.	Eskom Holdings Ltd
Consumers Energy Company	EDP - Energias do Brasil S.A.	Korea Electric Power Corporation
Florida Power & Light Company	Emera Incorporated	Northern Illinois Gas Company
PG&E Corporation	The Empire District Electric Company	Tokyo Electric Power Company
Piedmont Natural Gas Company, Inc.	FirstEnergy Corp.	
The Southern Company	Indianapolis Power & Light Company	
Xcel Energy Inc.	Kyushu Electric Power Company	
	Oklahoma Gas and Electric Co.	
	PECO Energy Company	
	Progress Energy Carolinas, Inc.	
	Southern California Edison Company	
	Westar Energy, Inc.	
	Wisconsin Power and Light Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1: Regulatory Framework

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.	25%

Factor 2: Ability to Recover Costs and Earn Returns

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.	25%

Factor 3: Diversification

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

*10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/ Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Appendix B: Methodology Grid-Indicated Ratings

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	Aa3	Aaa	Aa	Aa	A	Aaa	A	Aa	Aa	Ba	Ba	Baa
Tokyo Electric Power Company, Incorporated	Aa2	A1	Aaa	Aa	Aa	A	Aaa	Baa	Aa	A	Ba	Ba	Ba
Eesti Energia AS	A1/[8]	A3	Baa	Baa	B	B	B	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	A1	A	A	Baa	Baa	Baa	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	Baa1	Baa	Baa	Baa	Baa	A	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A2	A	A	A	A	A	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa1	Baa	Baa	A	A	N/A	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A3	Baa	A	Baa	Baa	Baa	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A3	A	A	Baa	Baa	Baa	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa1	Baa	A	Baa	Baa	N/A	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	Baa1	Baa	Baa	Baa	Baa	N/A	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	A3	A	A	A	A	N/A	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A2	A	A	Baa	Baa	A	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	Baa1	Baa	Baa	Baa	Baa	A	A	A	A	A	A	Baa
The Southern Company	A3	A3	A	A	Baa	A	Ba	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa1	Baa	Baa	A	Baa	Aa	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa2	Baa	Baa	Baa	A	Ba	Baa	Baa	Baa	Baa	Baa	Ba

Regulated Electric and Gas Utilities

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Arizona Public Service Company	Baa2	Baa2	Ba	Baa	Baa	Baa	Baa	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa2	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A3	Baa	A	Baa	A	Baa	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Baa1	A	A	Ba	Ba	Ba	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa3	Ba	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2[13]	Ba1	Ba	Ba	B	Ba	B	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa1	Baa	A	Ba	Baa	Ba	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	Baa2	Ba	Ba	Ba	Ba	N/A	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa2	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa2	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa3	Ba	Ba	Baa	Baa	Baa	Baa	Ba	Baa	Aa	A	A

Positive Outlier

Negative Outlier

Appendix C: Observations and Outliers for Grid Mapping

Results of Mapping Factor 1

Factor 1: Regulatory Framework

Factor Weight		25%
	Current Rating /BCA	Regulatory Supportiveness
Kyushu Electric Power Company, Incorporated	Aa2	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aaa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	Baa
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	Baa
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	Baa
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Ba
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	Baa
Duke Energy Corporation	Baa2	Baa
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Ba
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	Baa
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

As a utility's regulatory framework is one of the most important drivers of ratings, there are no outliers for this factor among the 30 issuers highlighted for this methodology.

Results of Mapping Factor 2

Factor 2: Ability to Recover Costs and Earn Returns		
Factor Weight		25%
	Current Rating/BCA	Rate Adjustment and Cost Recovery Mechanisms
Kyushu Electric Power Company, Incorporated	Aa2	Aa
Tokyo Electric Power Company, Incorporated	Aa2	Aa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	A
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	A
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	A
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Baa
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	A
Duke Energy Corporation	Baa2	A
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Baa
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	A
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

Like Factor 1, Regulatory Framework, the ability to recover costs and earn returns is also an important ratings driver for regulated utilities, and it is not surprising that there are no outliers among the 30 issuers highlighted. For this factor, most of the issuers score exactly at their current rating levels, with the remainder scoring within one notch of their actual rating.

Results of Mapping Factor 3

Factor 3: Diversification

Sub-Factor Weights			5% *	5% **
	Current Rating/BCA	Indicated Factor 3 Rating	Market Position	Generation and Fuel Diversification
Kyushu Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Eesti Energia AS	A1/[8]	B	B	B
Florida Power & Light Company	A1	Baa	Baa	Baa
Korea Electric Power Corporation	A2/[6]	Baa	Baa	A
CLP Holdings Limited	A2	A	A	A
Northern Illinois Gas Company	A2	A	A	N/A
Oklahoma Gas and Electric Company	A2	Baa	Baa	Baa
Wisconsin Power and Light Company	A2	Baa	Baa	Baa
Consolidated Edison Company of New York	A3	Baa	Baa	N/A
PECO Energy Company	A3	Baa	Baa	N/A
Piedmont Natural Gas Company, Inc.	A3	A	A	N/A
Progress Energy Carolinas, Inc.	A3	Baa	Baa	A
Southern California Edison Company	A3	Baa	Baa	A
The Southern Company	A3	Baa	A	Ba
PG&E Corporation	Baa1	A	Baa	Aa
Xcel Energy Inc.	Baa1	A	A	A
American Electric Power Company, Inc.	Baa2	Baa	A	Ba
Arizona Public Service Company	Baa2	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa
Dominion Resources, Inc.	Baa2	A	A	A
Duke Energy Corporation	Baa2	Baa	A	Baa
Emera Incorporated	Baa2	Ba	Ba	Ba
The Empire District Electric Company	Baa2	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	B	Ba	B
Indianapolis Power & Light Company	Baa2	Ba	Baa	Ba
Cemig Distribuição S.A.	Baa3	Ba	Ba	N/A
FirstEnergy Corp.	Baa3	Baa	A	Baa
Westar Energy, Inc.	Baa3	Ba	Baa	Ba
EDP - Energias do Brasil S.A.	Ba1	Baa	Baa	Baa

Observations and Outliers

Of the 30 issuers highlighted, there are three outliers, including PG&E Corporation as a positive outlier, due to their high degree of generation diversification and the lack of coal in their generation mix, and both Eesti Energia AS and The Southern Company as negative outliers. As an Estonian vertically integrated dominant electric utility, Eesti Energia is exposed to considerably high concentration risk as it operates in one of the smallest CEE emerging markets. The concentration risk is further worsened by the company's high reliance on one fuel source as its generation is fully based on internationally rare oil shale. Furthermore, as the oil shale generation is relatively CO2 intensive, Eesti Energia is further exposed to the development of CO2 allowance prices. The Southern Company is one of the largest coal generating utility systems in the U.S., with a high percentage of its generation from carbon fuels.

Results of Mapping Factor 4

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Sub-Factor Weights			10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-WC / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	A	Aa	Aa	Ba	Ba	Baa*
Tokyo Electric Power Company, Incorporated	Aa2	Baa	Aa	A	Ba	Ba	Ba*
Eesti Energia AS	A1/[8]	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	A	A	A	A	A	Baa
The Southern Company	A3	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Arizona Public Service Company	Baa2	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa	Ba	Baa	Aa	A	A

*Debt/RAV

Positive Outlier
Negative Outlier

Appendix D: Definition of Ratios

Cash Flow Interest Coverage

(Cash Flow from Operations – Changes in Working Capital + Interest Expense) / (Interest Expense + Capitalized Interest Expense)

CFO pre-WC / Debt

(Cash Flow from Operations – Changes in Working Capital) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

CFO pre-WC - Dividends / Debt

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Debt / Capitalization or Regulated Asset Value

(Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) / (Shareholders' equity + minority interest + deferred taxes + goodwill write-off reserve + Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) or RAV

Appendix E: Industry Overview

The electric and gas utility industry consists of companies that are engaged in the generation, transmission, and distribution of electricity and/or natural gas. While many utilities remain vertically integrated with operations in all three segments, others have functionally or legally unbundled these functions due to legislatively mandated market restructuring or other deregulation initiatives and may be engaged in just one or two of these activities.

The **generation** of electricity is the first step in the process of producing and delivering electricity to end use customers and typically the most capital intensive, with the largest portion of the industry's assets consisting of generating plants and related hard assets. Electricity is generated from a variety of fuel sources, including coal, natural gas, or oil; nuclear energy; and renewable sources such as hydro, wind, solar, geothermal, wood, and waste.

Transmission is the high voltage transfer of electricity over long distances from its source, usually the location of a generating plant, to substations closer to end use customers in population or industrial centers. Although many utilities own and operate their own transmission systems, there are also several independent transmission companies included in this methodology.

The **distribution** of electricity is the process whereby voltage is reduced and delivered from a high voltage transmission system through smaller wires to the end-users, which consist of industrial, commercial, government, or retail customers of the utility. Most of the utilities covered by this methodology are engaged to some degree in the distribution of electricity through "poles and wires" to their end customers. The distribution of natural gas entails the transport of gas from delivery points along major pipelines to customers in their service territory through distribution pipes.

Regulation Plays a Major Role in the Industry

Because of the essential nature of the utility's end products (electricity and gas), the public policy implications associated with their provision, the demands for high levels of reliability in their delivery, the monopoly status of most service territories, and the high capital costs associated with its infrastructure, the utility industry is generally subject to a high degree of government regulation and oversight. This regulation can take many forms and may include setting or approving the rates or other cost recovery mechanisms that utilities charge for their services (revenue), determining what costs can be recovered through base rates, authorizing returns that utilities earn on their investments, defining service territories, mandating the level and reliability of electricity and gas service that must be provided and enforcing safety standards. From a credit standpoint, the regulators' ability to set and control rates and returns is perhaps the most important regulatory consideration in determining a rating.

In the U.S., the most important utility regulator for most companies is the individual state agency generally known as the Public Utility Commission or the Public Service Commission. The commissions are comprised of elected or appointed officials in each state who determine, among other things, whether utility expenditures are reasonable and/or prudent and how they should be passed on to consumers through their utility rates. While some states have legislatively mandated certain market restructuring or deregulation initiatives with regard to the generation segment of their electricity markets, the majority of states remain fully regulated, and some states that had deregulated are in the process of "re-regulating" their electricity markets.

The key federal agency governing utilities in the U.S. is the Federal Energy Regulatory Commission (FERC), an independent agency that regulates, among other things, the interstate transmission of electricity and natural gas. The FERC's responsibilities include the approval of rates for the wholesale sale and transmission of electricity on an interstate basis by utilities, power marketers, power pools, power exchanges, and independent system operators. The Energy Policy Act of 2005 increased the FERC's regulatory authority in a wide range of areas including mergers and acquisitions, transmission siting, market practices, price transparency, and regional transmission organizations.

In Europe, following the implementation of specific policies relating to the liberalization of energy supply within the European Union (EU), the electric utility sector has been evolving toward a model targeting complete separation between network activities, regulated in light of their monopoly nature, and supply and production of energy, fully liberalized and hence unregulated. As a result of this process, most Western European utilities currently operate either as fully regulated entities in the networks segment, or largely unregulated integrated companies (albeit some may still maintain some regulated network activity), and are therefore excluded from the scope of this methodology. Nevertheless, there are countries in Europe where regulatory evolution and transition to competition remain at an earlier stage (Central and Eastern European countries and the Baltic states in particular) and/or are characterized by the remoteness and isolation of their systems (the islands in the Azores and Madeira regions for example). In these countries, Governments and/or Regulators maintain greater influence on the bulk of the utilities' revenues, thus supporting their inclusion in this methodology.

In Japan, regulation has been an important positive factor supporting utility credit quality. Japan's regulator makes the maintenance of supply its primary policy objective, followed in priority by environmental protection and finally, allowing market conditions to work. This approach preserves the utilities' integrated operations and makes them responsible for final supply to users in the liberalized market. The Japanese government is gradually deregulating the utility industry and expanding the liberalized market. However, the pace of deregulation has been moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of generation supply security.

In Australia, stable and predictable regulatory regimes continue to underpin the investment-grade characteristics of the sector. So far, regulators – which operate independently from the governments – have not adopted an aggressive stance to revenues and returns as they seek a balance between: appropriate returns for utilities; ongoing incentives for network investments; and appropriate prices for consumers. The supportiveness of the regimes will become increasingly important over the medium term as the sector undertakes investments to expand network capacity and replace ageing assets to meet rising demand.

In Asia Pacific (ex-Japan), regulation of electric utilities is overseen by government regulatory bodies in their respective countries. As such, the stability and regulatory framework can vary to a large extent by country with a few utilizing automatic cost pass through mechanisms while the majority operate with ad hoc tariff adjustments. However, power security remains a key policy objective and regulators continue to seek to ensure stability in regulatory and operating environments. Such regulatory environments are critical to attracting investments for both privatizations and for funding expanding electricity projects. Reform of the power industry in Asia remains slow paced and competition is well contained. Regulators have shown that they will reform in a prudent manner and allow tariff adjustment to minimize any material negative impact on the credit profiles of their power utilities. Such a supportive approach enhances stability and provides a stable regulatory regime which in turn remains a key driver in supporting the cash flows of Asia Pacific (ex-Japan) utilities.

In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies. Accordingly, the transparency and stability of regulation and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory frameworks in each jurisdiction are well established and there is a high expectation of timely recovery of cost and investments. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the U.S. Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors, to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes. As a result of the relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers.

In Latin America, there is a perceived lower level of regulatory supportiveness than in other regions. In Argentina, although the generation industry is deregulated, the government continues to intervene in the process of setting prices and tariffs. In addition, collections from sales to the spot market have only been partial and have depended on the government's discretion. Moody's views the current regulatory framework as a relatively high risk factor given the government's interference, the unclear regulations, the lack of support for the companies' profitability, and the lack of incentives for much needed long-term investment. Brazil's power generation companies could also be affected by unfavorable regulatory decisions, since about 75% of its electricity currently goes to the regulated market, but Moody's last year noted improvements in Brazil's regulatory environment, which led to several issuer upgrades. Brazil's regulatory model provides a more supportive environment for acceptable rates of return since the current rules for electric utilities are more transparent and technically driven. Nonetheless, there is a lower assurance of timely recovery of costs and investments in Brazil since the new framework has not yet experienced the stress of high inflation, exchange rate devaluation or electricity rationing. Recent distribution tariff review reductions have typically been in the high-single-digit range, which is considered modest, particularly compared to Moody's rated issuers in El Salvador (14% reduction) and Guatemala (45% reduction) both of which led to downgrades last year. The regulatory framework in Chile, in Moody's opinion, comes closest to the United States in terms of regulatory supportiveness.

Appendix F: Key Rating Issues Over the Intermediate Term

Global Climate Change and Environmental Awareness

Electric and gas utilities will continue to be affected by growing concerns over global climate change and greenhouse gas emissions, which are particularly important in the electricity generation segment which continues to rely on a large number of coal and natural gas fired power plants. There have been significant increases in environmental expenditure estimates among utilities with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. Utilities may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants has been cancelled as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to higher coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

While the global recession may have reduced electric demand in certain regions in the short-term, longer-term worldwide demand for electricity is expected to continue to grow and many utilities will incur substantial capital expenditures for new generation, as well as for upgrades and expansions to transmission systems. In the U.S., the Edison Electric Institute projects annual capacity additions among investor-owned utilities to increase to over 15,000 megawatts (MW) in 2009 compared with less than 6,000 MW in 2006. Some of the new plants announced include large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years. In Indonesia, the Fast Track program calls for the addition of 9,000 MW of coal-fired power plants while India plans to build eight ultra-mega power projects (each under 4,000 MW). Similar large nuclear plants are being constructed worldwide in countries as diverse as Bulgaria, China, India, Russia, South Korea, Taiwan and Ukraine. Because of this construction boom, international demand for certain construction materials, plant components and skilled labor has driven up the cost of new nuclear. More recently, the global economic slowdown may relieve some of this cost pressure.

Political and Regulatory Risk

As the utility industry faces higher operating costs, rising environmental compliance expenditures, large capital expenditures for new generation, as well as fuel and commodity price risks, the need for rate relief and other regulatory support will continue to be a key rating factor. In the U.S., political intervention in the regulatory process following particularly large rate increase requests increased risk and negatively affected the credit ratings of utilities in Illinois and Maryland in recent years. In Europe, rising electricity prices two years ago resulted in widespread criticism of utilities in several countries, increasing regulatory and political risk for some of them. In Australia, the transition from state based regulation to a national regulatory framework could pose a moderate level of uncertainty to current regulatory thinking over the longer term. In Asia Pacific (ex-Japan) and Latin America, the governments face political pressure regarding tariff adjustments given their need to balance socio-economic targets and inflationary concerns against the objective of ensuring reliable electricity supply over the long term.

Economic and Financial Market Conditions

Although electric and gas utilities are somewhat resistant (although not immune) to unsettled economic and financial market conditions due partly to the essential nature of the service provided, a protracted or severe recession could negatively affect credit profiles over the intermediate term in several ways. Falling demand for electricity or natural gas could negatively impact margins and debt service protection measures. Poor economic conditions could make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally,

constrained capital market conditions could severely limit the availability of credit necessary to finance needed capital expenditures, or make such financing plans more expensive.

Appendix G: Regional and Other Considerations

Notching Considerations - Structural Subordination and Holding Company Ratings

Utility corporate structures often include multiple legal entities within a single consolidated organization under an unregulated parent holding company. The holding company typically has one or more regulated operating subsidiaries and may have one or more unregulated subsidiaries as well. Most utility families issue debt at several of these legal entities within the organizational family including the parent holding company and the utility subsidiaries. In such cases, our approach is to assess each issuer on a standalone basis as well as to evaluate the creditworthiness of the consolidated entity. We also consider the interdependent relationships that may exist among affiliates and the degree to which a management team operates its utility subsidiaries as a system. We then assess the degree of legal and regulatory insulation that exists between the generally lower-risk regulated entities and the generally higher-risk unregulated entities.

The degree of notching (or rating differential) between entities in a single family of companies depends on the degree of insulation that exists between the regulated and unregulated entities, as well as the amount of debt at the holding company in comparison to the consolidated entity. If there is minimal insulation or ring-fencing between the parent and subsidiary and little to no debt at the parent, there is typically a one notch differential between the two to reflect structural subordination of the parent company debt compared to the operating subsidiary debt. If there is substantial insulation between the two and/or debt at the parent company is a material percentage of the overall debt, there could be two or more notches between the ratings of the parent and the subsidiary.

U.S. Securitization

Since the late 1990s, legislatively approved stranded cost and other regulatory asset securitization has become an increasingly utilized financing technique among some investor-owned electric utilities. In its simplest form, a stranded cost securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitizations were originally done to reimburse utilities for stranded costs following deregulation, which was primarily related to the actual lower market values of the legacy generation compared to its book value. More recently, securitizations have been done to reimburse utilities for storm restoration costs following two active hurricane seasons in the U.S. in 2004 and 2005, with additional securitizations planned following an active 2008 hurricane season, as well as for environmental equipment. In 2007, Baltimore Gas & Electric used securitization to fund supply cost deferrals. Securitization could also be used to help fund the next generation of nuclear plants to be built in the U.S.

Although it often addresses a major credit overhang and provides an immediate source of cash, Moody's treats securitization debt of utilities as being on-credit debt. In calculating balance sheet leverage, Moody's treats the securitization as being fully recourse to the utility as accounting guidelines require the debt to appear on the utility's balance sheet. In looking at cash flow coverages, Moody's analysis focuses on ratios that include the securitized debt in the company's total debt as being the most consistent with the analysis of comparable companies. Securitizations also entail transition or other charges on ratepayer bills that may limit a utility's flexibility to raise rates for other reasons going forward. While our standard published credit ratios include the securitization debt, we also look at the ratios without the securitization debt and cash flow in our analysis, to distinguish this debt and ensure that the benefits of securitization are not ignored.

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership dominate Asia Pacific (ex-Japan) power utilities and remain one of their key rating drivers. The current majority state ownership levels are expected to remain largely unchanged for the near to medium term, thereby providing rating uplift to a majority of the government-owned Asia Pacific (ex-Japan) utilities under the Joint Default Analysis methodology.

Appendix H: Treatment of Power Purchase Agreements ("PPA's")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, or to fix the cost of power. While Moody's regards these risk reduction measures positively, some aspects of PPAs may negatively affect the credit of utilities.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover debt service and are made irrespective of whether the utility requires the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.[4]

Factors determining the treatment of PPAs

Because PPAs have a wide variety of financial and regulatory characteristics, each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized. Factors which determine where on the continuum Moody's treats a particular PPA are as follows:

- Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.
- Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- Price considerations: The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it

[4] When take-or-pay contracts, outsourcing agreements, PPAs and other rights to capacity are accounted for as leases under US GAAP or IFRS, they are treated by Moody's as such for analytical purposes.

does not require it for its own customers, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may have a material impact on the utility's cash flow.

- Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totaled 42.0% of its operating costs in FY2008. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.
- Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.
- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's debt, in the same way as other off-balance sheet items.[5]
- Accounting: From a financial reporting standpoint, very few PPA's have thus far resulted in IPP's being consolidated by the off taker. Similarly, very few PPA's are treated as lease obligations. Due to upcoming accounting rule changes[6], however, coupled with many contracts being renegotiated and extended over the next several years, we expect to see an increasing number of projects being consolidated or PPA's accounted for as leases on utility financial statements. Many of the factors assessed in the accounting decision are the same as in our analysis, i.e. risk and control. However, our analysis also considers additional factors that the accountants may not, such as the ability to pass through costs. We will consider the rationale behind the accounting decision and compare it to our own analysis and may not necessarily come to the same conclusion as the accountants.

Each of these factors will be weighed by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods of accounting for PPAs in our analysis

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total debt obligations for the utility using one of the methods discussed below.

- Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the debt obligations of the utility. In the event operating costs are consolidated, we will attempt to deconsolidate these costs from a utility's financial statements.
- Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot be quantified otherwise due to limited information.

[5] See "The Analysis of Off-Balance Sheet Exposures – A Global Perspective", Rating Methodology, July 2004.
[6] SFAS 167 "Amendments to FASB Interpretation No. 46(r)" will be effective Q1 2010.

- Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be the cost of capital of the utility.
- Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.
- Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility will be added to its total debt obligations.
- Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the effect of the PPA on the credit of the utility.

Moody's Related Research

Industry Outlooks:

- U.S. Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U.S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Analyst Contacts *(continued)*:

London **44.20.7772.5454**

Raffaella Altamura
Analyst

Monica Merli
Team Managing Director

Hong Kong **852.3551.3077**

Jennifer Wong
Assistant Vice President - Analyst

Gary Lau
Senior Vice President

Sydney **61.2.9270.8100**

Clement Chong
Vice President – Senior Analyst

Terry Fanous
Senior Vice President

Brian Cahill
Managing Director/Australia

Tokyo **81.3.5408.4100**

Kenji Okamoto
Vice President – Senior Analyst

Report Number: 118481

Author	Associate Analyst	Production Specialist
Michael G. Haggarty	Mitchell Moss	Yelena Ponirovskaya

Moody's Investors Service

FitchRatings
KNOW YOUR RISK

Corporates

Global Power
North America
Special Report

EEI 2008 Wrap-Up: Cost of Capital Rising

Analysts

Philip W. Smyth, CFA
+1 212 908-0531
philip.smyth@fitchratings.com

Ellen Lapson, CFA
+1 212 908-0505
ellen.lapson@fitchratings.com

Sharon Bonelli
+1 212 908-0581
sharon.bonelli@fitchratings.com

Glen Grabelsky
+1 212 908-0577
glen.grabelsky@fitchratings.com

Robert Hornick
+1 212 908-0523
robert.hornick@fitchratings.com

Related Research

- *20th Annual Global Power Breakfast: Investing in an Unpredictable World, Nov. 14, 2008*

Clouds Gathering

The 43rd Edison Electric Institute Financial Conference convened Nov. 9–12, 2008, in Phoenix, Ariz. The storm clouds rolling through Phoenix on Sunday, the first day of the assembly, provided a gloomy backdrop, matching the subdued sentiments of investors, analysts and corporate officers. The uncertainties facing the electric utility and power generation industry reflected the ongoing financial crisis and a deepening U.S. and global recession. Aside from credit market dislocations and worsening economic indicators, conference participants speculated about the potential policy directions of a new Obama administration and Democratic majority in the U.S. Congress in such areas as taxes and dividends, energy conservation and renewables, coal and nuclear power.

Five key themes that appeared repeatedly in management presentations were:

1. Weakening trends in unit sales of electricity.
2. Increased focus on liquidity positions and capital market access.
3. Higher cost of capital.
4. Regulatory lag affecting the ability to recover higher cost of capital.
5. Initiatives to reduce discretionary capital spending and external financing needs.

The outlook is considerably sunnier for the FERC-jurisdictional electric transmission subsector, a business with cash flows that are immune to variations in sales volumes and insulated from regulatory lag.

Representative Rick Boucher (Democrat, Virginia's 9th District) delivered the clear message at the plenary session keynote on Monday that enactment of legislation restricting carbon emissions will be a priority of President-elect Obama's administration and the U.S. Congress in 2009, second only to the top priority of stabilizing financial markets and fixing the economy, no small task. Rep. Boucher sought the support of the utilities present for his bill to fund the development and deployment of carbon capture and sequestration technology through a nongovernment corporation that would receive its funding from a fee collected upon sales of electricity.

The biggest news story of the conference happened off-site. On Monday Nov. 10, NRG Energy Inc. (NRG, IDR 'B', Rating Watch Evolving) invited conference attendees to an investor meeting to discuss NRG management's rejection of a $6 billion stock-for-stock merger offer from Exelon Corp. (EXC, IDR 'BBB+', Rating Watch Negative). On Tuesday, Nov. 11, EXC announced it would take its takeover offer directly to shareholders, without any change in the exchange ratio. The announcement of the hostile bid is a rarity in the power sector. Fitch Ratings placed EXC's ratings on Ratings Watch Negative when the original offer for NRG was announced on Oct. 20, 2008. In Fitch's view, the change to a hostile bid has no incremental affect on EXC's rating or Negative Watch status.

Investing in an Unpredictable World

Fitch's 20th Annual Global Power Breakfast theme was "Investing in an Unpredictable World." Michael W. Howard (Senior Vice President of Research and Development, Electric Power Research Institute [EPRI]) provided an overview of recent developments and expectations regarding plug-in and extended range electric vehicles. Ellen Lapson and Glen Grabelsky, both Managing Directors with Fitch Ratings, discussed salient credit trends affecting the power and gas sector, including the implications of the ongoing credit and capital markets on a sector that invests in long-lived and long lead-time infrastructure assets and relies heavily upon access to new debt and equity markets.

Lapson as moderator observed that Stable Rating Outlooks dominate Fitch's universe of issuers, but downgrades and Negative Outlooks have outpaced upgrades and Positive Outlooks in 2008 year to date, a distinct change in trend from the more favorable ratios in 2004–2007. The ratio of Positive to Negative Outlooks is now 0.8:1; however, 87% of Rating Outlooks in this sector are Stable.

Grabelsky discussed the major themes currently shaping credit in the power and gas sector, including the deleveraging in financial markets, decelerating growth in unit sales of power, high capital investment budgets, inadequate equity returns in some jurisdictions, and regulatory lag. A substantial decline in natural gas, coal and other commodity prices since peaking at the end of June is a constructive development for the power and gas sector. However, Grabelsky noted that the extreme volatility in gas prices poses a real problem for the sector, and despite the steep recent drop, the trend continues to show progressively rising troughs. Meanwhile, funding costs for new debt for a 'BBB' utility, in the range of 9% and higher, are now bumping up against authorized returns on equity, which average 10.25%–10.5% for the industry, and are as low as 9.1% in New York and New Mexico. He opined that if the cost of new debt remains at this level, significantly higher regulated returns will be required to attract equity capital.

Despite the challenges facing the electric utility industry, Grabelsky acknowledged that the sector benefits from relatively stable underlying cash flows vis-à-vis other industries and should benefit in relative terms as investors seek safer investments in a difficult macroeconomic environment. Utilities have demonstrated continued access to commercial paper and term debt markets throughout the market turmoil, albeit at higher cost. Lapson noted that the utility power and gas sector is better positioned today than in the sector crisis of 2000–2003, when many if not most companies had profound business problems due to failed diversification strategies. Today, companies are more prudently capitalized and have simplified their businesses, but must adapt their business strategies to the challenging financing environment.

In a different vein, Mike Howard of EPRI provided an update on the nascent market for plug-in electric vehicles. Howard forecasted that by 2030, plug-in vehicles would aggregate 16 million cars on the road, or roughly 5% penetration. Howard said that the introduction of electric vehicles was unlikely to drive incremental capital investments needs for new generation facilities at any time soon, but the impact could be more stressful on local distribution circuits and substations. The estimated annual load of a plug-in hybrid vehicle with a 40-mile range was estimated by Howard at 2,500 kilowatt-hours (kWh) per annum, about the same as the load of three plasma TVs along with three set-top boxes. Electric utilities will need to get their distribution networks, meters, pricing and billing systems ready for drivers charging their cars at home, at work and on the road.

General Session

Rep. Boucher discussed draft legislation expected to be introduced in the next Congress (Boucher-Dingell bill) to reduce carbon dioxide emissions by up to 80% later this century, and emphasized that the economic impact of such regulations would be more manageable if the implementation is consistent with the available control technology. Therefore, carbon dioxide reductions are back-end loaded under the proposed legislation to allow technology to catch-up with the proposed carbon reductions. Boucher has introduced another bill to create a separate funding mechanism to finance carbon capture and sequestration technology, targeting development by 2020. This initiative recognizes the crucial role of coal-fired generation in meeting the nation's power requirements without undue reliance on natural gas.

Rep. Boucher's request for comments on the discussion draft for the planned cap and trade bill was a clear call to arms for the industry to actively join the debate regarding the energy policy and carbon-related issues in particular. He pointedly noted that carbon regulation will be implemented either legislatively or administratively through the Environmental Protection Agency (EPA). Unlike the EPA, a legislative approach is more likely to weigh economic considerations. Rep. Boucher favors a cap-and-trade approach along with a distribution of allowances, eschewing the auction approach, to reduce carbon emissions. Free allocation of allowances would be favorable for utility cash flows, but may not meaningfully reduce emissions.

Rep. Boucher also indicated that President-elect Obama views the greenhouse gas issue as second in importance only to efforts to right the nation's ailing financial markets and economy.

Rep. Boucher proposes creation of a one mill (that is, one-tenth of a cent) per kWh charge that would raise approximately $1 billion to fund the development of carbon capture and sequestration technology by 2020. This is a bill that has united the interests of utilities in coal-producing states, the coal industry and unions.

Fitch notes that it is difficult to handicap at this time the likelihood of the 2009 passage of either bill, given the significant economic challenges that will capture the immediate attention of lawmakers. If the new Democratic administration and legislative majority succeed in passing a carbon control regime, whether cap and trade or a carbon fee, the carbon costs would be credit neutral to those utilities able to pass through the associated costs in customer rates in a timely manner and could affect ratings of utilities with less efficient recovery mechanisms or nonregulated generators that cannot recover the costs in existing power purchase agreements or through higher market power prices.

Smart Grid Panel

The first panel on Monday, Nov. 10, 2008, directly followed Rep. Boucher's remarks and discussed the evolution and future of the smart grid. The panel was moderated by Ron Insana (Managing Director, SAC Capital Advisors) and included Richard C. Kelly (Chairman, President and Chief Executive Officer [CEO], Xcel Energy, Inc.), Philip Mezey (Chief Operating Officer, Itron North America), David M. Ratcliffe (Chairman, President and CEO, Southern Co.), Robert S. Shapard (Chairman and CEO, Oncor Electric Delivery) and Barry T. Smitherman (Chairman, Public Utility Commission of Texas).

The panelists did not provide a definition for "smart grid," and it was clear that the term had different meanings for each panelist. For the record, Fitch understands "smart grid" to mean a transmission and distribution system that uses advanced sensing, communication and control technologies to generate and distribute electricity

more effectively and securely. The enhancements are expected to detect and address emerging problems on the system before they affect service; provide extensive measurements, rapid communications, centralized diagnostics and feedback control; and support interactions with customers or with sensors on customers' appliances.

The panel participants generally agreed that investments in a smart grid will facilitate energy efficiency as well as integrating more renewable energy mandates in coming years. Two panelists expressed the view that the cost associated with these investments would be offset in part by operating savings. For other panelists, the benefits would come from better fulfilling consumer needs and expectations for high quality of service and interaction with their electricity supply and costs. We learned about cyber-security risks created by any new portal into the electric grid, as well as about privacy risks created by the utility having such detailed information about its customers' consumption patterns.

Carbon Regulation Panel

Participants in the second panel discussion included Rep. Boucher, as well as William D. Johnson (Chairman, CEO and President, Progress Energy, Inc.) Kevin McCullough (CEO, RWE Innogy GmbH), James Miller (Chairman, CEO and President, PPL Corporation, and Richard Sandor (Chairman and CEO, Chicago Climate Exchange). Boucher reiterated that his proposed legislation would provide the industry with the means to fund and develop new technology to burn coal cleanly, as summarized above.

Miller noted carbon capture would reduce plant efficiency and that the timing of the new technology remains uncertain. Johnson wondered if experimental technology available today would indeed be effective in large-scale application and about the cost to build the necessary infrastructure to transport and store carbon.

According to Sandor, sending the proper price signals regarding emission credits would be a crucial aspect of the overall solution, agreeing with Rep. Boucher that cap and trade is the best approach. Rep. Boucher asked for utility and power company input and support on the discussion draft. He expects a final version of draft carbon control legislation to be introduced early next year and that the bills would move to the Senate in the fall of 2009.

The panelists agreed that a rush to natural gas as the fuel of choice for new generation is problematic and should be avoided, but with coal out of favor and significant cost hurdles to nuclear construction and permitting timelines, natural gas appears to be the de facto fuel of choice. From a credit viewpoint, Fitch agrees that the likely increased dependence on natural gas is troubling, given the extreme volatility and the rising trend in gas prices, as evidenced by progressively higher prices at each trough.

Company Strategies and Tactics

External Capital Requirements

Liquidity and efforts to reduce external capital requirements were high on investor and management agendas. Slowing growth of unit sales as the result of economic weakness should provide utilities with an opportunity to reduce planned capacity additions commensurately. However, in Fitch's view, decelerating growth is likely to provide relatively modest utility capital investment reductions, with the possible exception of certain historically high-growth states such as Nevada, Arizona and Florida, where the greatest reversal in demand has occurred. For example, Pinnacle West Capital subsidiary Arizona Public Service Co. (APS) has cut capital expenditures meaningfully, with the large majority of the savings reflecting a sharp slowdown in customer growth to an expected 1% rate in 2008 and 2009 from its historical 4% per annum customer growth rate.

Fitch believes the majority of utility investment is focused on reliability, renewable energy and related transmission or environmental projects that are, for the most part, not discretionary. As a result, management is likely to defer, not cancel, long-lived projects.

New investments in FERC-jurisdictional transmission facilities remain an attractive investment opportunities even in the face of constrained capital markets, and for the most part, companies intend to stay the course. However, we learned that some transmission projects may be delayed if their purpose was to connect new wind-fired capacity to the load centers; wind projects in the planning stage may not get built in today's lower gas price environment.

Management of PEPCO Holdings affirmed its intention to continue its aggressive build-out of transmission projects, despite the poor market reception for PEPCO's recent capital issuance. Northeast Utilities provided a new five-year forecast with significant transmission investment and an impressive projection of earnings growth. NSTAR also expects its earnings growth, projected at 6%–8%, to be driven by significant transmission investment opportunities; there are five competing projects under review by ISO New England, each of which terminates in NSTAR's service territory. Allegheny Energy, AEP and Dominion continue to pursue major transmission projects in the PJM region. However, permitting remains a time-consuming challenge.

Nonregulated competitive generation subsidiaries may cut back their capital spending materially. Companies that announced reductions to discretionary capital expenditure in their competitive businesses for 2009 include Ameren, FPL Energy, PPL Energy, and Public Service Enterprise Group. Some generators or integrated utilities plan to delay air-quality control investments to the extent that they were driven by Clean Air Interstate Rule (CAIR) requirements that have been remanded to the EPA by the appellate court, while other companies said that they must continue their environmental spending to meet state standards that remain in force.

Regulatory Considerations

Jurisdictional regulatory practices promise to be a key element in determining the ultimate impact on issuer creditworthiness given the sharp increase in the cost of capital as a result of the ongoing financial crisis. Utilities in states that have authorized reasonable returns on equity and adopted balanced regulatory mechanisms, including forward test years and automatic fuel and other tariff adjustment mechanisms are more likely to come through this period of stress without undue deterioration to current creditworthiness.

In general, vertically integrated utilities in the Southeast U.S. tend to have more constructive regulatory environments. California electric utilities Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison have tariff decoupling mechanisms that insulate their credit from a downturn in sales as well as the potential for annual adjustments to the return on equity (ROE) component in their rates. Cost of capital reviews are conducted on a three-year cycle but adjusted if a particular bond index yield increases by more than 100 basis points (bps) in a given year. If the index rate changes by more than 100 bps, the cost of debt is reset and ROE is adjusted to reflect half the change in the index.

Conversely, the ratings of utilities operating in states with relatively low authorized ROEs and significant regulatory lag are more likely to suffer future credit deterioration, in Fitch's view. States with challenging regulatory environments include Arizona, Missouri, New Mexico, New York and Vermont.

Transition to market-based generation rates continues to be an issue in Ohio and Pennsylvania. The Public Service Commission of Ohio is expected to rule imminently on FirstEnergy Corp.'s Ohio operating electric utility subsidiaries' filed proposal under Ohio Substitute Senate Bill 221, which could result in adoption of the company's Electric Security Plan (ESP) or a market-based plan effective in 2009. In Fitch's view, the adoption of an ESP is the more likely outcome. In Pennsylvania, Fitch anticipates that the policymakers may seek to extend utility rate caps, which are scheduled to terminate in 2010–2011 for Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power & Light, West Penn Power, and Philadelphia Electric Co.

STANDARD
&POOR'S

RATINGSDIRECT®

January 23, 2009

Credit FAQ:

Top 10 Investor Questions For The U.S. Electric Utilities Sector In 2009

Primary Credit Analyst:
John W Whitlock, New York (1) 212-438-7678; john_whitlock@standardandpoors.com

Table Of Contents

Credit FAQ:

Top 10 Investor Questions For The U.S. Electric Utilities Sector In 2009

(Editor's Note: In the article published Jan. 22, 2009, we erroneously stated that CenterPoint Energy Inc. had issued a common equity offering. In fact, CenterPoint Energy Houston Electric LLC had issued $500 million in bonds. A corrected version follows.)

Standard & Poor's Ratings Services' forecast for the U.S. electric sector is for a stable ratings trend. The recession will continue to pressure cash flows and debt balances, but we expect most companies to weather 2009. Our forecast is backstopped by expectations of responsive regulatory decisions and continued access to debt and equity markets, which should provide sufficient cushion to maintain stability for the majority of companies. Those companies that fare poorly in the regulatory arena and experience significant deterioration in cash flow metrics and creeping debt leverage are most vulnerable to downward actions. Substantial capital spending needs and the potential for incremental costs to implement the Obama Administration's energy priorities limit upward ratings for the sector.

The following questions and answers are a representative sample of the credit issues that electric utilities will face in the coming year, including the weak economic environment, a drop in customer usage, delayed capital expenditures, costlier debt financing, and impending energy policy.

Frequently Asked Questions

Do you expect electric utilities to continue to have access to capital markets throughout 2009?

Credit ratings for the regulated electric sector incorporate our expectations that it can tap currently constricted capital markets. Challenging conditions that tested electric utilities' resiliency in 2008 included an unexpected contraction in short-term funding sources, loss of some banking syndicate members including Lehman Brothers Holdings, and an intermittent lack of investor appetite for even lower risk utility debt. Utility managements took some prudent financial steps in 2008, including increasing the size of credit facilities and prefunding debt maturities before the financial distress gained steam during the year.

For 2009, the electric utility sector is well positioned to benefit from possible investor demand for debt instruments issued by established market names with a good performance record and sustained investment-grade credit quality. Of course, investors are demanding higher coupons to complete deals with tenors ranging between five and 10 years; notably covenant protection has not been required to date outside of existing first mortgage bond indentures. Standard & Poor's expects that the most liquid of instruments will continue to be utility first mortgage bonds, which are backstopped by the utilities' physical plant and robust recovery prospects.

Although the economic slowdown may mute the need for debt issuance associated with building new plants, market activity is occurring. Some companies completed several debt offerings in January, including PacifiCorp's $1 billion issuance of first mortgage bonds with a 10-year tranche at 5.5% and a 30-year tranche at 6% and CenterPoint Energy Houston Electric LLC's $500 million general mortgage bonds with a five-year maturity at 7%. In addition, Progress Energy Inc. and PEPCO Holdings Inc. have strengthened their balance sheets in recent months with

common equity offerings.

What types of regulatory challenges are at the forefront in 2009?

During this recession, regulators may come under pressure to dampen rate hikes. This creates a quandary for regulated electric utilities that plan their spending several years in advance. The companies' have initially responded to the recessionary slowdown by pulling back on 2009 spending. However, this can be viewed only as a stop-gap measure. Continued reliance on this strategy for a prolonged period could heighten the perception of reliability deterioration. Several companies expect rate decisions during the first quarter of 2009, including Union Electric Co. in Missouri, American Electric Power Co. Inc.'s Ohio units, Southern California Edison Co., and Idaho's IDACORP Inc., and we'll be looking out for how the companies deal with declining electricity sales due to the recession. Regulatory bodies that defer prudently incurred costs during a period of declining electricity sales could harm credit quality.

During the past five years, regulated electric utilities and their ratepayers have benefited from historically low interest rates and cost of capital. Clearly, the pendulum swung back toward the mean in 2008; current rates of 500 basis points over Treasuries for 10-year 'BBB' debt (e.g., Metropolitan Edison Co.'s $300 million unsecured notes) reflect this market reevaluation. Most utilities are operating under an authorized cost of debt that in some instances falls well short of actual debt pricing in today's marketplace. Standard & Poor's expects that regulators will begin reflecting the "new" cost of debt in customer rates. Regulators' willingness to recognize the higher cost of capital through overall returns is important for credit quality.

The changes in Washington in 2009 provide the Federal Energy Regulatory Commission (FERC) with an opportunity to reshape interpretation of energy policy. A re-emphasis on regulation in all industries may lead to more intervention by the FERC.

How will the new Administration's potential energy policy affect credit ratings?

At this stage, it is uncertain what credit challenges electric utilities will face under a new energy plan. Lower prices for crude oil and other commodities, combined with the depth of the recession, have likely pushed back the starting line. It will be interesting to see if the Obama Administration will propose substantial energy policy changes in its first 100 days. As the bartering in Congress begins, coal and new nuclear plants are endangered, and solar and wind are the rage. Comments by some Obama appointees indicate that coal, at least in a cleaner form, and maybe a few new nuclear plants, may have a place at the table.

What is certain is that the industry is changing. Companies are implementing alternative energy sources such as wind and solar to meet mandated renewable standards. How quickly utilities can recover the "green" that they spend to "go green" will largely determine how they maintain credit quality. These expenses include all ancillary costs, including those for transmission upgrades and additional peaking units needed to back up renewable resources that are frequently intermittent in nature.

Reducing carbon emissions in some form or manner, an Obama campaign promise, could affect ratings, depending on how ready, willing, and able local regulators are to allow utilities to pass along federally mandated costs to their customers. Companies were able to pass through previous costs for environmental standards to ratepayers, but at amounts much lower than a potential carbon tax or trading scheme. Just how—and how long it takes—companies to implement their carbon emission reduction will also factor into ultimate credit quality.

How important is liquidity for regulated electric utilities?

As we saw in the fourth quarter of 2008, electric utilities benefit greatly from ample liquidity. Having the ability to meet maturities eases refinancing pressures and exudes confidence to investors. This backstop allowed electric utilities to maintain access to the bond market during 2008 in all market conditions. Strong liquidity positions are a factor that bolsters electric utilities' credit profiles.

Several utilities faced significantly higher collateral calls in second-half 2008 due to sharply falling commodity prices. In some cases, collateral calls, combined with pending maturities, led to a somewhat urgent need to add additional liquidity facilities. It's important that those facilities are big enough to address future volatility in commodity prices.

Companies whose facilities expire later in 2010 and into 2011 will have to renew them at more burdensome terms. In the past, utility credit facilities have been unsecured, but that may change in the future. In addition, banks are introducing pricing based on credit default swaps for some industries, including utilities. Standard & Poor's has commented that using instruments such as those swaps may actually compromise expected liquidity access in times of market stress. (See "Methodology And Assumptions: Analysis Of Corporates' Swap-Indexed Bank Lines," published Dec. 16, 2008 on RatingsDirect.)

What is the status of deregulation throughout the U.S.?

Deregulation can best be described as stalled. For instance, the transition period for most electric providers in Pennsylvania will come to a close in 2010. Standard & Poor's expects that the rate increase in Pennsylvania will be manageable, averaging 10% to 15%, although double-digit increases during prolonged economic sluggishness could create pressure. Economic malaise in Ohio has ensnarled the completion of transition plans for providers, especially FirstEnergy Corp.'s units.

The recent travails of Constellation Energy Group Inc. have Maryland leaders considering whether to order the conversion of Baltimore Gas & Electric Co. back into a fully integrated regulated company. The difficulty is that BG&E previously sold all its generating assets as part of the original move to deregulation. Reassembling the regulated entity is a costly proposition, but reintroducing the utility's ability to self-build could happen, as it has in places like Nevada and Connecticut. In 2008, Virginia abandoned deregulation. However, it's a much less painful process for Virginia Electric & Power Co. because it never sold its generating assets.

What's the industry's growth strategy?

Before the economy went down, the growth strategy for the industry was to build power plants that they could put into their "rate-base" (the value of property on which a utility may earn a specified rate of return according to a regulatory authority) and increase assets and income through regulatory decisions. Management often targeted annual growth of 8% to 9%.

With robust capital spending likely postponed at least until 2010, earnings growth for the interim period will be sluggish. A return to a more aggressive strategic direction that includes investment in nonregulated businesses and results in higher business or financial risk would pressure credit profiles. Often, the financing of these nonregulated ventures is with leverage levels more suitable for the regulated utility asset.

How much capital spending can utilities delay without straining infrastructure?

With the slowdown and drop in customer demand for electricity, companies can delay the start of some long lead-time projects. They can also postpone a minimal amount of maintenance capital before jeopardizing service

quality. Any reliability neglect--whether actual or perceived--will have a long-lasting affect on regulatory relations. Also, maintaining older infrastructure requires capital outlay.

Very little of the regulated transmission spending that companies have budgeted can be deferred considering calls from Washington for a "smarter grid" and the probable influx of renewable resources. Stricter carbon emission standards may also trigger a shutdown of older coal units, requiring spending for new, differently fired plants.

Will regulated electrics be able to build large, base-load plants?

Under the right circumstances, electric utilities will be able to build large rate-based plants. The primary consideration for how they preserve credit quality is the regulatory approval process. In the case of building new nuclear plants, we expect regulated electric utilities to have an established regulatory compact that allows them to recover costs throughout the building cycle. It's important for credit that utilities can recover these costs as they expense them. This eliminates prudency risk, customer rate shock, and excessive balance-sheet bloating.

Accurate cost estimates and negotiating contractor terms that fix a large portion of the construction expense will help keep balance sheets strong. The ability to abandon projects and recover expenses if mishaps, cost escalation, or regulatory angst occur is also beneficial to utility credit.

How important is balance-sheet strength when determining electric utility credit quality?

The electric utility industry is asset-intensive and relies heavily on debt. Balance-sheet strength is a distinguishing factor when Standard & Poor's assesses financial risk and determines credit quality. Our analysis attempts to portray the economic reality of the financial conditions and considers several items, including purchase power obligations, capital leases, hybrid equity instruments, pension liabilities, and regulatory assets.

In a period of economic decline, the strength of recovery mechanisms and the timely recovery of costs, including those for bad debt and other deferrals, keep balance sheets flexible. Monitoring leverage balances and avoiding creeping leverage caused by slow receipt of cash flow and the simultaneous conversion of short-term debt into long-term debt is important to balance-sheet strength.

Encouraging energy efficiency without recovery mechanisms burdens coverage ratio metrics. While customers are changing their consumption patterns, decoupling mechanisms allow utilities to recoup lost sales revenue. This helps mitigate cash flow pressures when usage goes down due to economic decline.

Will industry consolidation ramp up in 2009?

Standard & Poor's continues to believe that selective industry consolidation is possible in 2009, but wide-scale combinations are unlikely. Macquarie Infrastructure completed its deal for Puget Energy Inc. in about 16 months, which shows how long it can take to get regulatory approval to complete deals.

Given the length of the regulatory approval process, it's a tall order for managements to commit the time, resources, and financial obligations in a dwindling economy. However, one variable that may weigh more favorably for mergers is battered stock prices in the industry. This makes the stock-for-stock financing alternative more attractive and may spur more deals, especially if growth remains elusive.

Moody's Investors Service

Global Credit Research
Credit Opinion
19 JUN 2009

Credit Opinion: Progress Energy Florida, Inc.

Progress Energy Florida, Inc.

Florida, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A2
Senior Secured Shelf	(P)A2
Senior Unsecured	A3
Subordinate Shelf	(P)Baa1
Preferred Stock	Baa2
Commercial Paper	P-2
Ult Parent: Progress Energy, Inc.	
Outlook	Stable
Senior Unsecured	Baa2
Jr Subordinate Shelf	(P)Baa3
Preferred Shelf	(P)Ba1
Commercial Paper	P-2

Contacts

Analyst	Phone
Michael G. Haggarty/New York	212.553.7172
William L. Hess/New York	212.553.3837

Key Indicators

[1]
Progress Energy Florida, Inc.

ACTUALS	LTM 1Q09	2008	2007	2006
(CFO Pre-W/C + Interest) / Interest Expense [2]	3.5x	3.0x	4.7x	7.9x
(CFO Pre-W/C) / Debt [2]	12.6%	9.8%	19.1%	38.6%
(CFO Pre-W/C - Dividends) / Debt [2]	12.5%	9.8%	19.0%	30.4%
(CFO Pre-W/C - Dividends) / Capex [2]	43.5%	32.7%	56.8%	116.5%
Debt / Book Capitalization	56.1%	56.6%	52.3%	47.4%
EBITA Margin	15.8%	15.7%	12.8%	14.0%

[1] All ratios are calculated using Moody's Standard Adjustments [2] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

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

Opinion

Rating Drivers

Large pending rate case; traditionally supportive regulatory environment

Substantial capital expenditure program, despite nuclear plant construction delay

Lower credit metrics in 2008 should improve in 2009 as fuel costs are recovered

High parent company debt

Liquidity affected by higher collateral postings for natural gas hedges

Corporate Profile

Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF, A3 senior unsecured, stable outlook) is a vertically integrated public utility with approximately 1.6 million customers in the north central part of Florida and 9,360 MW of generation capacity. It is one of two major utility subsidiaries of Progress Energy, Inc. (Progress, Baa2 senior unsecured, stable outlook), which is also the parent of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC, A3 senior unsecured, stable outlook).

Recent Events

In May 2009, PEF announced a delay in the construction schedule for its Levy County nuclear project by at least 20 months, with the units now not expected to be completed until the 2018-2020 time frame.

In March 2009, PEF filed a petition with the Florida Public Service Commission (FPSC) requesting a $499 million increase in base rates.

In January 2009, Progress Energy issued 14.4 million shares of common stock at an offering price of $37.5 per share, generating net proceeds of $523 million.

SUMMARY RATING RATIONALE

PEF's A3 Issuer Rating reflects an above average regulatory environment for electric utilities in the state of Florida; a historically high growth service territory that has been recently negatively affected by a housing and economic slowdown; and coverage metrics that have declined over the last year due to fuel cost deferrals and collateral postings. The rating also considers a large pending base rate case filed during a period of slow economic growth in Florida, rising operating costs; large capital expenditure requirements for environmental compliance; and higher long-term debt to finance these expenditures. The company has relieved some near term capital expenditure and financing pressure with its recent decision to postpone the construction schedule for its new Levy County nuclear generating plant.

DETAILED RATING CONSIDERATIONS

- PEF has a large base rate increase pending, although the state of Florida has been a traditionally supportive regulatory environment for electric utilities that Moody's expects to continue

PEF operates under traditional rate of return regulation and recovers fuel capacity and environmental costs through separate rate adjustment mechanisms. The utility currently operates under a rate settlement that runs through 2009 with base rates frozen, although there have been adjustments to base rates for new plants brought on-line. In March 2009, PEF filed for a $499 million increase in base rates based on a 12.54% return on equity. In a recent positive development, in May 2009, the FPSC approved an interim base rate increase, plus an additional $63.1 million to recover the costs of repowering its Bartow generating plant. Hearings on the remainder of the case begin in September with a decision expected by November 2009. The requested increase reflects recovery for investments in both its generating fleet and in its transmission and distribution systems. If the full amount of the base rate increase is approved by the FPSC, the new base rates would increase the average residential bill by approximately $15.00 per 1,000 kWh or 11%. PEF is also able to prospectively file for rate adjustments for expected changes in fuel costs and in April 2009, PEF reduced rates by $206 million (5%) due to lower projected fuel costs.

Although the state of Florida has historically been an above average regulatory environment for electric utilities, there is a degree of regulatory uncertainty regarding PEF's current rate case. The size of the rate case is substantial and comes at a time when the state's growth has slowed. Furthermore, none of the current members of the FPSC were on the Commission at the time PEF's last rate case was settled in 2005. Offsetting these risks to some extent was the interim relief granted to PEF, as well as the FPSC's recent decision in Tampa Electric's rate case, both of which have affirmed Moody's view that the regulatory environment for electric utilities in Florida has remained relatively supportive.

- The utility is in the midst of a substantial capital expenditure program for environmental compliance and new generation, which has been somewhat reduced over the near term by the delay in its nuclear construction plans

PEF projected capital expenditures to be at least $1.3 - $1.7 billion annually from 2009 through 2011 in its 2008 10-K, consistent with the elevated levels the company experienced in 2007 and 2008, although totals for 2009 and 2010 will likely decrease by a few hundred million dollars as a result of the recently announced delay in its nuclear plant construction plans. The company has proposed recovering $299 million of nuclear costs incurred through 2009 over a five year period through 2014. PEF is able to recover its environmental expenditures through separate riders which help maintain PEF's credit metrics. Moody's expects PEF's construction spending to be financed by a combination of debt at the utility and capital contributions from the parent. PEF's total debt to capitalization is expected remain in the low to mid-50% range going forward, including Moody's standard adjustments.

By far the company's largest capital expenditure project is the construction of a new two-unit (1,105 MW per unit) nuclear facility in Levy County, about ten miles from its Crystal River nuclear facility. The new units are estimated to cost a substantial $14 billion along with $3 billion for transmission upgrades, and PEF is hoping to have one or more co-owners share in the construction costs. Although PEF has spent $243 million on preconstruction and construction spending through 2008, significant capital expenditures will likely not be made until the post-2010 time frame.

On May 1, 2009, PEF announced that the construction schedule for the new nuclear units had been delayed by at least twenty months with a new online date in the 2018-2020 time frame. The delay results from the company's determination that the excavation and foundation preparation work will not be authorized until the Nuclear Regulatory Commission issues a combined operating license (COL), which is not expected until late 2011 or early 2012. Although the delay has shifted some capital expenditures for the project out by at least 20 months, the project still poses a considerable long-term risk and will require continued supportive regulatory treatment and assured, timely cost recovery provisions.

- Lower cash flow coverage metrics in 2008 caused for the most part by deferred fuel; metrics are expected to return closer to prior year levels in 2009 and 2010

Credit metrics declined significantly in 2008 due to higher deferred fuel that will be recovered in 2009 and should lead to a recovery of cash flow coverage ratios. These ratios include CFO pre-working capital interest coverage of 3.0x and CFO pre-working capital to debt of 9.8% in 2008, down from 4.7x and 19.1%, respectively, in 2007. Results for the twelve months ending March 31, 2009 have already shown some improvement with CFO pre-working capital interest coverage increasing to 3.5x and CFO pre-working capital to debt increasing to 12.6%. Over the long-term, the utility's coverage metrics will remain pressured by higher operating costs, as well as significant debt issuances in both 2007 and 2008 to meet capital expenditure requirements. PEF will continue to experience higher levels of capital expenditures over the next several years, though much of the incremental spending is environmental and will be recovered through cost recovery clauses. Moody's expects PEF's metrics to return to levels more appropriate for an A rated utility with CFO pre-working capital interest coverage above 4.0x and CFO pre-working capital to debt above 20% over the intermediate term, although the degree of improvement is somewhat dependent on its rate case outcome.

- High parent company debt

PEF's overall risk profile has benefited from a lower business risk profile at parent company Progress Energy following the divestiture of several unregulated businesses over the last several years, which allowed the parent company to reduce debt by $1.7 billion to $2.6 billion or approximately 25% of the total long-term debt of the consolidated entity. However, in March 2009, Progress again increased the level of debt at the parent company by issuing $750 million of senior notes to fund utility (mostly PEF) capital expenditures through equity contributions, increasing parent company debt to $3.35 billion, or approximately 30% of the total consolidated debt of the Progress Energy organization. Offsetting some of the risk of this additional debt was the issuance of $523 million of equity (net proceeds) in January 2009, which Moody's viewed as credit positive. The high level of debt at the parent company is the predominant reason behind the relatively wide notching between the unsecured rating of Progress at Baa2 and its utility subsidiaries at A3.

Liquidity Profile

PEF has been reliant on the parent company for liquidity support over the last several months because of unusually high collateral requirements related to natural gas hedges. As a result of a significant decline in natural gas prices since those hedges were executed, PEF has been required to post cash collateral of $535 million as of March 31, 2009, up from $335 million at December 31, 2008. Rather than fully utilizing PEF's own $450 million credit facility to meet these collateral requirements, Progress Energy had $500 million drawn on its own credit facility as of March 31, 2009 and has temporarily advanced funds to the utility to meet these collateral requirements. As a result, PEF had $514 million of notes payable to affiliated companies (both the parent and PEC) on its balance sheet as of March 31, 2009, up from $72 million at December 31, 2008. Progress anticipates that collateral requirements at PEF will decrease by the end of 2009 as these hedges begin to roll off. Progress

Energy also made a $155 million equity contribution to PEF during the first quarter of 2009, for the most part for PEF's large ongoing construction program.

PEF's $450 million bank revolving credit facility expires on March 28, 2011, which supported $130 million of commercial paper outstanding as of March 31, 2009. The credit facility does not contain a material adverse change clause that could preclude new borrowings, and has one financial covenant, a maximum debt-to-capital covenant of 65%. At March 31, 2009, the company was in compliance with the financial covenant with a calculation of 57.9%. Long-term debt due at PEF over the next twelve months is limited to a $300 million first mortgage bond maturity on June 1, 2010. PEF had $20 million of cash on hand as of March 31, 2009, about equal to the $19 million it held at December 31, 2008.

The company expects to finance higher capital expenditures with a combination of internally generated funds, long-term debt issuances, and/or equity contributions from the parent company. The utility can supplement these sources with access to Progress Energy's money pool, which allows the parent to more efficiently allocate cash among its two regulated utility subsidiaries

Progress Energy maintains a $1.13 billion revolving credit facility expiring May 3, 2012 that supports the parent company's commercial paper program. The facility includes a covenant that limits the company's debt to capital ratio to 68%, and does not include a material adverse change representation for new borrowings. The company was in compliance with this covenant at March 31, 2009 with a debt to capital ratio of 57.1%

Rating Outlook

The stable rating outlook reflects a supportive regulatory environment, strong cost recovery provisions, and our expectation that cash flow coverage ratios will improve to prior year levels as fuel costs are recovered, collateral requirements decline, and new base rates are implemented. The stable outlook also reflects the company's decision to delay its nuclear construction program by at least 20 months, which will reduce near-term capital spending requirements and financing needs.

What Could Change the Rating - Up

An upgrade is unlikely while the utility has a major rate case pending and is undertaking a major new nuclear construction project. An upgrade could be considered, however, if there are significant mitigants to offset the risks inherent in such a large and complex nuclear construction project, including preapproval of recovery for nuclear capital expenditures, the sharing of risk with contractors or other parties; and the inclusion of co-owners or other partners. An upgrade could also be considered if there is a recovery of cash flow coverage metrics from currently low levels, including a ratio of CFO before working capital plus interest to interest above 5.0x and CFO before working capital to debt above 25%. The rating is somewhat constrained by the high level of debt at the parent company level.

What Could Change the Rating - Down

A downgrade could be considered if there is an adverse change in the regulatory environment in Florida which could limit full and timely recovery of costs, especially the cost of new nuclear generation; a continued increase in leverage; new, unanticipated capital expenditure requirements; if financial coverage metrics do not recover from 2008 levels and CFO before working capital plus interest to interest remains below 4.0x; and CFO before working capital to debt remains below 20% for a sustained period..

Rating Factors

Progress Energy Florida, Inc.
297000 3
Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

CREDIT RATINGS ARE MOODY'S INVESTORS SERVICE, INC.'S (MIS) CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES. MIS DEFINES CREDIT RISK AS THE RISK THAT AN ENTITY MAY NOT MEET ITS CONTRACTUAL, FINANCIAL OBLIGATIONS AS THEY COME DUE AND ANY ESTIMATED FINANCIAL LOSS IN THE EVENT OF DEFAULT. CREDIT RATINGS DO NOT ADDRESS ANY OTHER RISK, INCLUDING BUT NOT LIMITED TO: LIQUIDITY RISK, MARKET VALUE RISK, OR PRICE VOLATILITY. CREDIT RATINGS ARE NOT STATEMENTS OF CURRENT OR HISTORICAL FACT. CREDIT RATINGS DO NOT CONSTITUTE INVESTMENT OR FINANCIAL ADVICE, AND CREDIT RATINGS ARE NOT RECOMMENDATIONS TO PURCHASE, SELL, OR HOLD PARTICULAR SECURITIES. CREDIT RATINGS DO NOT COMMENT ON THE SUITABILITY OF AN INVESTMENT FOR ANY PARTICULAR INVESTOR. MIS ISSUES ITS CREDIT RATINGS WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.

Progress Energy Florida - Rate Case
Adjusted Credit Metrics
($ in millions)

	2010 As Filed			2010 With $499 Increase			2010 With $35M Reduction		
	Book	S&P	Moody's	Book	S&P	Moody's	Book	S&P	Moody's
(FFO+ Interest)/Interest									
Total FFO	864	942	908	1,172	1,250	1,216	842	920	886
Total Interest	303	351	318	303	351	318	303	351	318
(FFO + Interest)/Interest	**3.9**	**3.7**	**3.9**	**4.9**	**4.6**	**4.8**	**3.8**	**3.6**	**3.8**
FFO/Debt									
Total FFO	864	942	908	1,172	1,250	1,216	842	920	886
Total Debt	4,786	5,999	5,433	4,786	5,999	5,433	4,786	5,999	5,433
FFO/Debt	**18.1%**	**15.7%**	**16.7%**	**24.5%**	**20.8%**	**22.4%**	**17.6%**	**15.3%**	**16.3%**

FFO = Funds From Operations = Cash From Operations pre-Working Capital

The A Rating

By Steven M. Fetter

When I came to the Michigan Public Service Commission in 1987, the average regulated electric utility had a relatively solid credit rating—in the A- to BBB+ range, comfortably investment-grade—and utilities borrowed money for capital improvements rather easily. In 1992, close to 65 percent were A- or higher, and around 25 percent were in the BBB rating category. By 1998, 61 percent were A- or higher, with 31 percent in the BBB category.

Today the average rating for the sector is slightly above a BBB rating—still investment-grade, but now just 18 percent of electric companies are A- or higher, and more than 62 percent are in the BBB range.

The downward trend in utility ratings toward BBB seemed acceptable during the past decade—utilities could still borrow, relying on their regulated positions and growing demand, and dividend-paying stocks became more attractive to equity investors. It seemed that cash-flow and liquidity requirements no longer needed to be as high as for A-rated companies.

Today's capital markets, however, are experiencing a worldwide economic crisis, and the country is in severe recession. Indeed, the current economic turmoil has resulted in some utilities within the BBB category experiencing difficulty in accessing the capital markets. Even when capital is available, it is often at significantly higher costs and upon less favorable terms and conditions.

While the financial crisis has led to increases in debt and equity risk premiums for all utilities, these increases have been more consistently applied to utilities on the lower end of the credit rating scale, resulting in significantly higher cost of debt capital for BBB utilities than for A-rated ones. A December 2008 report released by J.P. Morgan, "Conservative Capital Structures: Reclaiming the Throne," opined that "generally, firms' lowest cost of capital is now reached at credit ratings that are about four notches higher than they were 18 months ago.... This trend is driven by a widening gap between the availability and costs of debt for higher and lower-rated firms." And as Garry Brown, chairman of the New York Public Service Commission says, "there is a clear relationship between a utility's bond rating and its ability to borrow at a reasonable cost, particularly in times of economic distress."

Unlike the broader industrial sector, which can delay capital investment in times of duress, electric utilities carry a responsibility to expend capital when needed to ensure safe and reliable service to customers. They do not have the option of substantially cutting back operations during difficult economic times. As Brown further notes, "Large capital programs... make it very important that electric utilities continue to have access to the financial markets, and regulatory policies should support utilities' ability to raise capital."

Flexibility in a Crisis

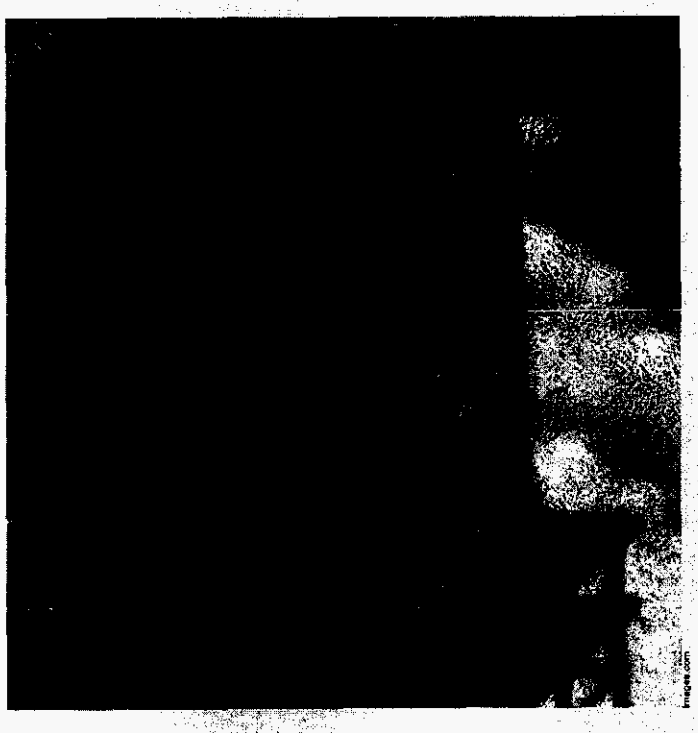
Here are two examples, admittedly extreme, that illustrate differing capabilities of an A-level utility and a BBB-level one. On September 11, 2001, Con Edison held an A+ credit rating. In the face of the terrorist events of that day, the utility was able immediately to initiate one of the largest infrastructure recovery efforts any industry has ever faced, without seeking special treatment from suppliers or lenders. The company's credit rating and outlook never stuttered as it proceeded to bring businesses in lower Manhattan back to full function.

In the other example, Entergy New Orleans had seen its corporate credit rating improve from BBB with a credit watch negative to BBB with a stable outlook. Then, in August 2005, Hurricane Katrina devastated the utility's infrastructure and customer base. Huge impacts, to be sure, but the utility also faced resistance from contractual counterparties to provide supplies and assistance. The utility soon filed for bankruptcy, allowing its parent company, Entergy Corporation, to provide $200 million in funds to support the long process of reorganization and recovery. (Entergy New Orleans emerged from bankruptcy in June 2007 with a BBB- rating.)

These examples came long before the current financial market crisis, but they demonstrate that a credit profile in the A category provides substantial flexibility for a regulated utility's management to respond to customer needs while respecting investor interests.

New Era

The discussions among executives, regulators, and Wall Street that focused on diversification in the 1980s and 1990s and industry restructuring in the 1990s and 2000s have now shifted to risk management, rate-recovery mechanisms, pre-approval, putting construction work in



progress into rate base, and other means of supporting utility credit profiles during periods of substantial capital investment. That change in focus should be encouraging for state regulators. Perhaps we have returned to a time when it would be in the interest of both companies and regulators to work in concert to support stronger credit profiles for regulated electric utilities (optimally in the A category), for the good of both consumers and investors. Even a strong BBB+ rating provides a measure of downside protection from the serious ills that would accompany a utility falling below investment-grade or even dropping to borderline BBB- status.

The bottom line is that electric utilities must collect sufficient cash flow through rates to maintain strong credit rating metrics. This is especially true for companies needing to proceed with major generation construction, notwithstanding the negative economic environment. S&P has highlighted cash flow as the single most critical aspect of all credit rating decisions. And liquidity is the lifeblood of day-to-day utility management flexibility.

To get the right amount can be rough going. In February 2009, to bolster liquidity and support their credit ratings, Ameren Corporation and Great Plains Energy substantially cut their dividends. The result on the equity side for those companies was a drop in stock price during the subsequent month of 35–45 percent. Certainly other utilities are watching the fallout from those decisions to determine whether internal cost-cutting can serve as more than a stopgap solution to liquidity stresses or whether they will have to follow the same volatile dividend reduction path.

Still, the A rating is positive for all stakeholders within the regulatory process—lower financing costs accrue to the benefit of customers through the ratemaking process; and the lower costs serve to maintain investor support and provide a degree of flexibility to respond to unforeseeable events.

Notwithstanding the current financial crisis, many utilities need to make substantial new capital investment, including a new generation of nuclear construction, to serve forecasted load growth. As a former state regulator and bond rater, I believe the optimal strategy is for utilities and their regulators to work in concert to ensure strong cash flow. Sustained and constructive regulatory support will be a major factor in how both investors and rating agencies will perceive electric utilities during these uncertain economic times. A shared commitment to financial stability will go a long way toward allowing A-rated companies to remain at that more secure level and provide hope for others that are endeavoring to move up to it.

Steve Fetter is president of Regulation UnFettered, former chairman of the Michigan PSC, and former head of the global power group at Fitch Ratings.

www.moodys.com

Special Comment

Moody's Global
Infrastructure Finance

June 2009

New Nuclear Generation: Ratings Pressure Increasing

Table of Contents:

Analyst Contacts:

New York 1.212.553.1653

Jim Hempstead
Senior Vice President

Dan Aschenbach
Senior Vice President

A.J. Sabatelle
Senior Vice President

Mike Haggarty
Vice President – Senior Credit Officer

Laura Schumacher
Vice President – Senior Analyst

William L. Hess
Team Managing Director

Summary

- Moody's is considering taking a more negative view for those issuers seeking to build new nuclear power plants
- Rationale is premised on a material increase in business and operating risk
- Longer-term value proposition appears intact, and, once operating, nuclear plants are viewed favorably due to their economics and no-carbon emission footprint
- Historically, most nuclear-building utilities suffered ratings downgrades—and sometimes several—while building these facilities
- Political and policy conditions are spurring applications for new nuclear power generation for the first time in years
- Nevertheless, most utilities now seeking to build nuclear generation do not appear to be adjusting their financial policies, a credit negative
- First federal approvals are at least two years away, and economic, political and policy equations could easily change before then
- Progress continues slowly on Federal Loan Guarantees, which will provide a lower-cost source of funding but will only modestly mitigate increasing business and operating risk profile
- Partnerships, balance sheet strengthening, bolstering liquidity reserves and "back-to-basics" approaches to core operations could help would-be nuclear utilities maintain their ratings

This Special Comment is an addendum to our prior research reports associated with the credit implications of building new nuclear generation in the U.S. These prior reports, entitled "New Nuclear Generating Capacity: Potential Credit Implications for U.S. Investor Owned Utilities" published in May 2008 and "New Nuclear Generation in the United States: Keeping Options Open vs Addressing An Inevitable Necessity" published in October 2007 are referenced in the back under the section Moody's Related Research.

Moody's Investors Service

Overview

It has now been three decades since the last, serious nuclear construction cycle. The 1979 accident at Pennsylvania's Three Mile Island nuclear power plant appears to have permanently affected the nation's views about building new nuclear power generation. As a result, substantial new regulatory procedures were implemented. Development and construction costs soared, recovery was challenged, and for many issuers, financial deterioration and ratings downgrades followed. For some, ratings recovery took years.

But while nuclear power remains a thorny political and policy issue today, the concept of building new facilities has gradually reawakened in recent years, offering a buffer against foreign energy dependence, unpredictable commodity prices, and heavily polluting fuel sources. As a result, several of the largest U.S. power companies in recent years have announced plans to pursue new nuclear generation.

This may eventually boost the country's options for power generation. But from a credit perspective, the risks of building new nuclear generation are hard to ignore, entailing significantly higher business and operating risk profiles, with construction risk, huge capital costs, and continual shifts in national energy policy. Project risks are somewhat more clear today than during the last build cycle, in the 1970s, since we now have a track record that measures nuclear power's operating performance; strong plant economics due to low fuel cost; proven efficient and safe operating capabilities; new and refined regulatory procedures; and more certainty over reactor designs before construction begins.

Less clear today is the effect that energy efficiency programs and national renewable standards might have on the demand for new nuclear generation. National energy policy has also begun eyeing lower carbon emissions as a key desire for energy production—theoretically a huge benefit for new nuclear generation—but the price tags associated with these development efforts are daunting, especially in light of today's economic turmoil. It isn't clear what effect such shifts, or changes in technology, will have for new nuclear power facilities.

Credit conditions are yet another question. Few, if any, of the issuers aspiring to build new nuclear power have meaningfully strengthened their balance sheets, and for several companies, key financial credit ratios have actually declined. Moreover, recent broad market turmoil calls into question whether new liquidity is even available to support such capital-intensive projects. (The U.S. Nuclear Regulatory Commission's (NRC) first Construction and Operating Licenses, or COLs, are expected to win approval in roughly 24-36 months, after which investment in these projects could well increase significantly.)

Moody's is considering applying a more negative view for issuers that are actively pursuing new nuclear generation. History gives us reason to be concerned about possible significant balance-sheet challenges, the lack of tangible efforts today to defend the existing ratings, and the substantial execution risk involved in building new nuclear power facilities.

Nuclear's "bet-the-farm" risk

The NRC says about 14 companies to date have submitted COL applications, proposing numerous new nuclear reactors for power generation. The first of these COL's is expected to be approved beginning in mid-2011. Many of the COL license applications include partners, but the next table lists the primary holding company entity behind each project, and our view of the activity level associated with the endeavor.

From a credit perspective, companies that pursue new nuclear generation will take on a higher business and operating risk profile, pressuring credit ratings over the intermediate- to long-term. Even so, we also believe companies will ultimately revise their corporate-finance policies to begin materially strengthening balance sheets and bolstering available liquidity capacity at the start of the construction cycle. In addition, we believe regulators will generally continue to support the long-term financial health of the utilities they regulate, and will authorize recovery of investments and costs over a reasonable timeframe.

Moody's believes there is a significant difference between new nuclear plants located adjacent to existing units from those that are greenfield projects. In our opinion, brown-field projects benefit from the existing infrastructure (including security plans), local political support and historical operating record of the existing units. We believe the U.S. Department of Energy also recognized this as well in the selection of the Southern Company's Vogtle; NRG's South Texas Project, SCANA's Summer and Constellation's Calvert Cliffs / Nine Mile projects. We ascribe a "high" activity level for these projects.

Many of the development plans appear to have been slowed down over the past 6 – 12 months for various reasons. We ascribe a "low" activity level to those projects. Other may have slowed down only modestly. For these projects, we ascribe a "medium" activity level.

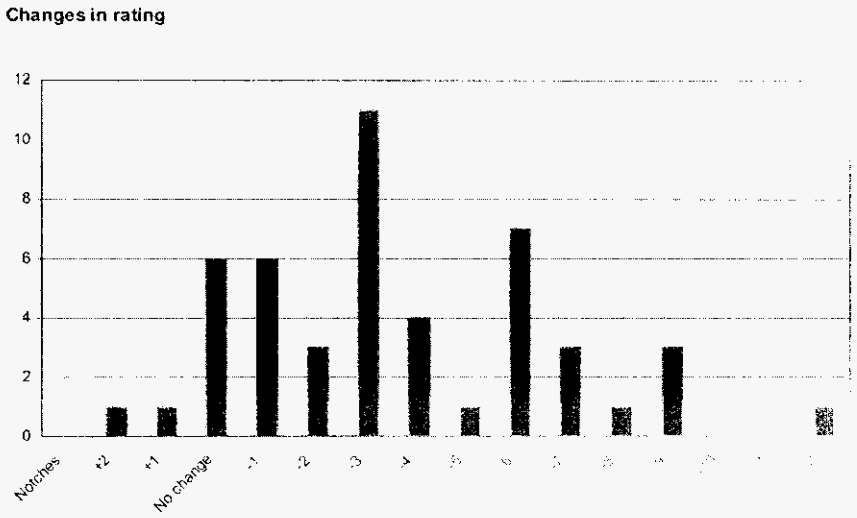
Table 1: COL applications received by the NRC

Company	Sr. Unsec.	Reactor Design	Proposed New Reactor	Activity Level
Ameren	Baa3	US EPR	Callaway	Low
Constellation	Baa3	US EPR	Calvert Cliffs	High
Constellation	Baa3	US EPR	Nine Mile Point	High
Dominion	Baa2	ESBWR	North Anna	Low
DTE Energy	Baa1	ESBWR	Fermi	Low
Duke Energy	Baa2	AP 1000	William S Lee	Medium
Energy Future Holdings	B3 CFR	US APWR	Comanche Peak	Low
Entergy	Baa3	ESBWR	Grand Gulf	Low
Entergy	Baa3	ESBWR	River Bend	Low
Exelon	Baa1	ESBWR	Victoria County	Low
NRG Energy	Ba3 CFR	ABWR	South Texas Project	High
PPL	Baa2	US EPR	Bell Bend	Medium
Progress	Baa2	AP 1000	Levy County	Medium
Progress	Baa2	AP 1000	Shearon Harris	Low
SCANA	Baa1	AP 1000	V.C. Summer	High
Southern	A3	AP 1000	Vogtle	High
TVA	Aaa	AP 1000	Bellefonte	Low

Historical rating trends are not good

Historical rating actions have been unfavorable for issuers seeking to build new nuclear generation. Of 48 issuers that we evaluated during the last nuclear building cycle (roughly 1965-1995), two received rating upgrades, six went unchanged, and 40 had downgrades. Moreover, the average downgraded issuer fell four notches. All of these ratings were evaluated on the senior secured or first mortgage bond ratings.

New Nuclear Generation: Ratings Pressure Increasing



We view new nuclear generation plans as a "bet the farm" endeavor for most companies, due to the size of the investment and length of time needed to build a nuclear power facility. While we continue to view operating nuclear units positively, we increasingly sense that none of the issuers actively pursuing these endeavors have taken any material actions to strengthen their balance sheets. As a result, it has become increasingly likely that the pursuit of new nuclear power projects will lead to some near-term rating actions or outlook changes.

This table highlights the credit metrics some of the issuers that appear most aggressive in their nuclear development plans.

Table 2: Selected utilities actively pursuing new nuclear generation

Company	Sector	Sr. Unsec.	Rating Outlook	2008 Debt*	2008 Revenue*	Debt / Revenue
South Carolina Electric & Gas	IOU	A3	Stable	$3,464	$2,816	123%
South Carolina Public Service Authority (Santee Cooper)	Municipal	Aa2	Stable	$3,715	$1,586	234%
Georgia Power	IOU	A2	Stable	$8,156	$8,412	97%
Municipal Electric Authority of Georgia	Municipal	A1	Stable	$3,390	$772	439%
Power South	Cooperative	Baa1	Stable	$1,398	$750	186%
Oglethorpe	Cooperative	Baa1	Stable	$3,910	$1,239	316%
San Antonio CPS	Municipal	Aa1	Stable	$3,600	$2,200	164%
City of Austin	Municipal	A1	Positive	$1,600	$1,200	133%
NRG Energy	Unregulated	Ba3 CFR	RUR-up	$9,275	$6,885	135%

** in $ millions*

Plant construction can pressure metrics

The sheer size, cost and complexity of new nuclear construction projects will increase a utility's or power company's business and operating risk profile, leading to downward rating pressure. The length of a nuclear construction effort also entails lengthy regulatory reviews and potential delays in recovering investments, changing market conditions, shifting political and policy agendas, and technological developments on both the supply and demand side.

Given these long-term risks, a company's financial policy becomes especially critical to its overall credit profile during construction. In general, we believe a company should prepare for the higher risk associated with construction by maintaining, if not strengthening, its balance sheet, and by maintaining robust levels of available liquidity capacity.

This is crucial, because our preliminary analysis suggests that credit metrics will deteriorate meaningfully without significant mitigating factors or other structural provisions. As cash outflows materially begin to outpace inflows, leverage is expected to increase and metrics related to cash flow are expected to decline. A weakening financial profile, coupled with increasing business and operating risk, should result in credit deterioration.

Precedents offer limited insight

Much has changed since the last major nuclear-generation construction cycle (1965-1995). The industry has learned from experience, including up-front regulatory oversight of development and investment; streamlined federal NRC approval procedures; and enhanced construction cycles and techniques.

In addition, new environmental regulations, specifically those aimed at reducing carbon dioxide emissions; appear well positioned for near-term implementation. These environmental developments should otherwise bolster the case for new nuclear generation, as it is viewed as one of the only large scale generation technology with a no-carbon footprint.

We are not questioning the arguments in favor of new large-scale nuclear generation. We observe, however, that nuclear projects require massive investments, and the long-term recovery of which presents a primary risk factor for issuers actively trying to build new nuclear power plants. Historically, in fact, many of the large nuclear utilities experienced some financial distress while building their plants. Material rating downgrades remain just as distinct a possibility today.

Issuer experience varied during the last U.S. nuclear build cycle, which we define as 1965-1995. This table is not meant to be all-inclusive (it excludes several issuers, such as Portland General and its Trojan nuclear plant. Although almost all issuers experienced rating downgrades to varying degrees, and not all of the downgrades may have been directly related to nuclear development, it was clearly either a primary or contributing factor in most cases.

Table 3: Precedent rating actions for utilities involved in nuclear development

Issuer	Period	Beginning rating	Lowest rating	Notches moved
Alabama Power	1975-1987	A2 FMB	Baa3	4
Arizona Public Service	1981-1993	A2 FMB	Baa3	4
Baltimore Gas & Electric	1974-1979	A2 FMB	A2	--
Cleveland Electric Illuminating	1981-1993	Aa2 FMB	Baa3	7
Commonwealth Edison	1968-1990	Aa2 FMB	Baa1	5
Connecticut Light & Power	1972-1978	Aa2 FMB	A2	3
Consolidated Edison Co of NY	1972-1978	A2 FMB	Baa2	3
Consumers Energy	1969-1974	Aaa FMB	Aa2	2
Detroit Edison	1985-1992	Baa1 SS	Baa2	1
Duke Energy Carolinas	1972-1986	Aa2 FMB	A2	3
Duquesne Light	1974-1988	Aa2 FMB	Baa2	6
Entergy Arkansas	1973-1979	A2 FMB	Baa2	3
Entergy Gulf States	1980-1988	A2 FMB	Ba3	7
Entergy Louisiana	1983-1988	Baa3 FMB	Ba2	2
Entergy Mississippi	1981-1987	A2 FMB	Ba2	6
Florida Power & Light	1972-1984	Aa2 FMB	A2	3
Georgia Power	1975-1990	Baa2 FMB	Baa2	--
Houston Light & Power	1987-1994	A2 FMB	A3	1
Illinois Power	1984-1989	A2 FMB	Baa3	4
Indiana Michigan Power	1973-1979	A2 FMB	Baa2	3
Iowa Electric Light & Power	1973-1977	Aa2 FMB	Baa2	6
Jersey Central Power & Light	1968-1980	A2 FMB	Ba2	6
Kansas Gas & Electric	1982-1986	Baa2 FMB	Baa3	1
Long Island Lighting	1972-1990	Aa2 FMB	B2	12
Metropolitan Edison	1973-1984	A2 FMB	B2	9
New England Power	1971-1992	Aa2 FMB	A1	2
Niagara Mohawk Power	1968-1988	Aaa FMB	Baa2	8
Northern Indiana Public Service	1973-1985	Aa2 FMB	Baa2	6
Northern States Power (MN)	1970-1976	Aa2 FMB	Aa2	--
NSTAR Electric	1971-1990	Aa2 FMB	Baa2	6
Ohio Edison	1975-1988	Aa2 FMB	Baa3	7
Pacific Gas & Electric	1983-1988	A1 FMB	A1	--
Philadelphia Electric Company	1973-1991	Aaa FMB	Baa3	9
PPL Electric Utilities	1982-1986	Aa2 FMB	A2	3
Progress Energy Carolinas	1970-1987	Aa2 FMB	Baa2	6
Progress Energy Florida	1975-1981	A2 FMB	A2	--
Public Service Co of Colorado	1976-1990	Aa2 FMB	A3	4
Public Service Co of New Hampshire	1980-1991	Baa2 FMB	Caa2	9
Public Service Electric & Gas	1973-1987	Aa2 FMB	Aa3	1
Puget Sound Energy	1978-1986	Baa2 FMB	A3	+2
Rochester Gas & Electric	1969-1975	Aa2 FMB	A2	3
South Carolina Electric & Gas	1979-1985	A2 FMB	A1	+1
Southern California Edison	1979-1985	Aa2 FMB	Aa2	--

Issuer	Period	Beginning rating	Lowest rating	Notches moved
Texas Utilities	1989-1995	Baa3 FMB	Baa3	1
Toledo Edison	1977-1988	Baa2 FMB	Baa3	1
Union Electric	1980-1988	A2 FMB	Baa2	3
Virginia Electric and Power	1971-1982	Aa2 FMB	A2	3
Wisconsin Public Service	1969-1975	Aa2 FMB	A2	3

Metrics show no meaningful improvement

Among electric utilities—both non-nuclear and nuclear vertically integrated companies—many key financial credit metrics have remained reasonably steady in recent times. While a stable financial profile reflects our sense of the sector's relative stability and predictability, we are becoming increasingly concerned that the nuclear utilities do not appear likely to see any meaningful improvement over the near to intermediate term.

Because companies that build new nuclear generation will increase their overall business and operating risk profiles, we believe they will need to compensate with near-term financial policies that produce strong financial credit ratios. While a constructive regulatory relationship will help mitigate near-term credit pressures, we will remain on guard for potential construction delays and cost overruns that could lead to future rate shock and/or disallowances of cost recovery. Given the lengthy construction time needed for nuclear projects, there is no guarantee that tomorrow's regulatory, political, or fuel environments will be as supportive to nuclear power as today's.

Table 4: Credit comparisons of nuclear and non-nuclear utilities

	Integrated Utility (non-nuclear) Average of 38 companies in peer group				Integrated Utility (nuclear) Average of 25 companies in peer group			
	7-yr	5-yr	3-yr	2008	7-yr	5-yr	3-yr	2008
Debt / Capitalization	43%	43%	42%	44%	42%	42%	42%	43%
Debt / EBITDA	3.8	3.2	3.3	3.8	3.0	3.0	3.3	3.3
Debt / Revenues	82%	80%	79%	83%	84%	82%	81%	86%
CFO / Debt	23%	22%	22%	18%	26%	26%	26%	24%
(CFO Pre-W/C) / Debt	24%	23%	22%	22%	27%	26%	26%	25%
FFO / Debt	26%	25%	24%	24%	27%	27%	26%	24%
EBITDA / Interest Expense	6.4	6.5	6.4	6.0	6.6	6.7	6.4	6.3
(CFO Pre-W/C + Interest) / Interest Expense	5.5	5.5	5.3	5.3	5.8	5.9	5.9	6.0
(CFO Pre-W/C-Dividends) / Capex	78%	72%	61%	60%	89%	83%	76%	69%
(CFO Pre-W/C-Dividends) / Debt	17%	17%	17%	17%	20%	20%	20%	20%

We can apply the same general financial-profile views to the parent companies that are now pursuing new nuclear construction:

Table 5: Credit conditions of parent companies seeking to build nuclear power generation

	Parent - nuclear Average of 14 companies in peer group			
	7-yr	5-yr	3-yr	2008
Debt / Capitalization	55%	54%	54%	56%
Debt / EBITDA	3.8	3.6	3.2	1.2
Debt / Revenues	131%	121%	123%	126%
CFO / Debt	17%	18%	18%	16%
(CFO Pre-W/C) / Debt	18%	19%	20%	18%
FFO / Debt	19%	20%	20%	19%
EBITDA / Interest Expense	4.5	4.7	4.8	4.3
(CFO Pre-W/C + Interest) / Interest Expense	4.2	4.4	4.4	4.2
(CFO Pre-W/C-Dividends) / Capex	101%	109%	87%	75%
(CFO Pre-W/C-Dividends) / Debt	14%	15%	15%	13%

Benefits of near-term recovery are limited

New nuclear power construction appears to enjoy strong political and regulatory support in a number of jurisdictions, especially in the southeastern states, where there is now legislation afoot to promote it. This support typically involves the regulators in the decision-making process on the business side; regular reviews of the sponsors' capital budgets; and real-time recovery of financing and other charges associated with the construction process.

Nevertheless, regulatory risks will persist over the longer term, and we increasingly think it unlikely that everything will work out as intended. We are concerned with the size of the investments being made even before the NRC grants a COL; the ongoing potential risks from displacement technology developments over the course of the construction period; and the recovery of sizeable sunk costs, should an issuer abandon a project in the future.

These longer-term risks are difficult to quantify today, but the possibility of abandoning a construction project should not be fully dismissed, regardless of the low probability of such an occurrence today. We remain concerned that should an issuer walk away from a nuclear project, for whatever reason, its multi-billion investment may not be fully recovered, or it may be amortized over a long-term period. This could introduce some material financial distress for almost any issuer.

Public Power and Cooperatives are positioned with flexible cost recovery mechanisms but rate pressure is expected

A number of municipally owned and not-for-profit cooperatives are partners in several new nuclear development projects. Several of these issuers have already begun raising significant amounts of debt to finance their share of the up-front development costs associated with these projects.

Public power utilities have begun to take proactive approaches to their participation in these projects to mitigate the burden. The Municipal Electric Authority of Georgia, for example, built a sizable reserve in excess of $700 million and found off takers for some of its initial ownership share to mitigate the financial burden of its ownership in the Vogtle 3 and 4 nuclear project. San Antonio CPS has begun to educate its customer base and to examine its rate process to begin to fund construction in advance of the construction schedule.

Nevertheless, despite their more levered balance sheets, we still consider the municipals and cooperatives better-positioned than the investor-owned utilities, because of their self-regulating rate authorities.

Yet one of the challenges associated with pursuing a new nuclear project is the size of the investment. These entities—like their investor-owned counterparts—risk the prospect that their customers will be unable to absorb steadily increasing rates. Ongoing economic turmoil in the U.S. amplifies this risk over the near to intermediate term and municipals and cooperatives do not have an ability to raise equity capital.

Is size an issue?

One possible solution might be for utilities to create partnerships for building new nuclear generation, thereby diluting this risk through various sharing mechanisms. Even some of the largest utility and power companies in our sector pale in comparison to the largest industrial customers, and to the foreign power companies, some of which could be strong candidates for such partnerships:

Table 6: Relative size comparison of other energy companies

Company	Sr. Unsec.	2008 Debt*	2008 Revenue*	2008 Assets
Large energy companies				
Electricity de France (EdF)	Aa3	$82,985	$87,833	$279,618
Exxon Mobil	Aaa	$56,596	$425,071	$295,024
BP plc	Aa1	$58,862	$361,143	$250,816
U.S. UTILITIES				
Exelon	Baa1	$18,069	$18,859	$48,524
Southern	A3	$20,276	$17,127	$49,380
Duke Energy	Baa2	$16,721	$13,207	$53,968
SCANA Corporation	Baa1	$4,972	$5,319	$11,567
NRG Energy	Ba3 CFR	$9,275	$6,885	$25,071

** in $ millions*

Conclusion

The likelihood that Moody's will take a more negative rating position for most issuers actively seeking to build new nuclear generation is increasing. With only about 24 months remaining before the NRC begins issuing licenses for new projects and major investment begins, few of the issuers we currently rate have taken any meaningful steps to strengthen their balance sheets. Considering these new projects tend to raise an issuer's business and operating risk profiles, the utility's overall credit profile appears weaker.

Most issuers still have some time to revise their financing policies. Even so, we are concerned that the turmoil in the financial markets, continued uncertainty associated with Federal loan guarantees, and the general tenor associated with bank credit facilities and liquidity will make such revisions more difficult in the future.

New Nuclear Generation: Ratings Pressure Increasing

In order to defend existing ratings, or to limit negative rating actions, we will look for investor-owned utilities to:

- create strategic partnerships, to share costs and risks;
- increase reliance on equity as a component to financing plans;
- moderate their dividend policies to retain cash flow; and
- adopt a "back-to-basics" focus on core electric utility operations, posing less distraction for management

In addition to this "back to basics" focus on core operations and management, we would expect municipal and cooperative utilities to increase up-front rates to consumers, in order to build liquidity cushions and prevent rate shocks.

From a risk mitigation perspective, the prospect of seeking business partners—particularly major multinational energy companies with some experience in the nuclear arena—might also be worth exploring as a good way to preserve liquidity and cash flow, while still reaping the benefits of new nuclear power generation.

Appendix A: Historical rating actions

Issuer	Period	Comment	Reactor
Alabama Power	1975-1987	A2 FMB downgraded to Baa2 in 1976, Baa3 in 1982, followed by multiple rating upgrades in 1983, 1984, 1985, 1986	Farley
Arizona Public Service	1981-1993	A2 FMB downgraded to A3 in 1982, Baa2 in 1984, Baa3 in 1989; upgraded to Baa2 in 1992	Palo Verde
Baltimore Gas & Electric	1974-1979	A2 FMB	Calvert Cliffs
Cleveland Electric Illuminating	1981-1993	Aa2 FMB downgraded to A2 in 1981, A3 in 1984, Baa2 in 1985, Baa3 in 1993	Perry
Commonwealth Edison	1968-1990	Aa2 FMB downgraded to A2 in 1980, A3 in 1984, Baa1 in 1987	Dresden / Quad Cities / Zion / LaSalle / Byron / Braidwood
Connecticut Light & Power	1972-1978	Aa2 FMB downgraded to A2 in 1974	Conn. Yankee / Yankee Rowe
Consolidated Edison Co of NY	1972-1978	A2 FMB downgraded to Baa2 in 1974	Indian Point
Consumers Energy	1969-1974	Aaa FMB downgraded to Aa2 in 1972	Palisades
Detroit Edison	1985-1992	Baa3 Sr. Sec. upgraded to Baa1 in 1985, downgraded to Baa2 in 1987 followed by upgrades to Baa1 in 1990, A3 in 1991	Fermi
Duke Energy Carolinas	1972-1986	Aa2 FMB downgraded to A2 in 1973; upgraded to A1 1982, Aa3 in 1983 and Aa2 in 1984	Oconee / McGuire / Catawba
Duquesne Light	1974-1988	Aa2 FMB downgraded to A2 in 1979, A3 in 1982, Baa1 in 1984 and Baa2 in 1987	Beaver Valley
Entergy Arkansas	1973-1979	A2 FMB downgraded to Baa2 in 1974	Arkansas Nuclear
Entergy Gulf States	1980-1988	A2 FMB downgraded to Baa2 in 1982, Baa3 in 1984, follow by upgrade to Baa2 in 1985 and downgrade to Ba2 in 1986 and to Ba3 in 1987	Riverbend
Entergy Louisiana	1983-1988	Baa3 FMB downgraded to Ba2 in 1985, followed by upgrade to Baa2 in 1986, downgraded to Ba2 in 1988 then upgraded back to Baa3 in 1988	Waterford
Entergy Mississippi	1981-1987	A2 FMB downgraded to A3 and again to Baa2 in 1982, downgraded to Ba2 in 1985, followed by upgrades to Baa2 and again to Baa1 in 1986	Grand Gulf
Florida Power & Light	1972-1984	Aa2 FMB downgraded to A2 in 1974, followed by upgrades to A1 in 1982 and Aa3 in 1984	Turkey Point / St. Lucie
Georgia Power	1975-1990	Baa2 FMB upgraded to Baa1 in 1982, downgraded to Baa2 in 1987	Hatch / Vogtle
Houston Light & Power	1987-1994	A2 FMB downgraded to A3 in 1989, upgraded to A2 in 1993	South Texas Project
Illinois Power	1984-1989	A2 FMB downgraded to A3 in 1986, to Baa2 in 1988 and Baa3 in 1989	Clinton
Indiana Michigan Power	1973-1979	A2 FMB downgraded to Baa2 in 1975	Cook
Iowa Electric Light & Power	1973-1977	Aa2 FMB downgraded to A2 in 1974, to Baa2 in 1975, followed by upgrade to A2 in 1977	Duane Arnold
Jersey Central Power & Light	1968-1980	A2 FMB downgraded to Baa2 in 1972 and Ba2 in 1980	Oyster Creek / Three Mile Island
Kansas Gas & Electric	1982-1986	Baa2 FMB downgraded to Baa3 in 1982, upgraded to Baa2 in 1986	Wolf Creek
Long Island Lighting	1972-1990	Aa2 Sr. Sec. downgraded to A2 in 1979, to Baa2 in 1980, upgraded to Baa1 in 1982, followed by downgrade to Baa3 in 1983, to B2 quickly followed by upgrade to Ba3 in 1984, Ba1 in 1989 and Baa3 in 1990	Shoreham
Metropolitan Edison	1973-1984	A2 FMB downgraded to Baa2 in 1979, B2 in 1980 followed by upgrade to Ba2 in 1984	Three Mile Island
New England Power	1971-1992	Aa2 FMB downgraded to Aa3 in 1982, A1 in 1988	Vt Yankee / Seabrook

New Nuclear Generation: Ratings Pressure Increasing

Issuer	Period	Comment	Reactor
Niagara Mohawk Power	1968-1988	Aaa FMB downgraded to A2 in 1968, A3 in 1982 and Baa1 in 1984 followed by upgrade to A3 in 1985 and downgrade to Baa1 in 1986, Baa2 in 1987 and upgrade to Baa1 in 1988	Nine Mile Point / Fitzpatrick
Northern Indiana Public Service	1973-1985	Aa2 FMB downgraded to Aa3 in 1982, to A3 in 1983 followed by upgrade to A1 in 1984 and downgrade to A2 and then to Baa2 in 1985	Bailly
Northern States Power (MN)	1970-1976	Aa2 FMB	Monticello / Prairie Island
NSTAR Electric	1971-1990	Aa2 FMB downgraded to A2 then to baa2 in 1974 followed by upgrade to A3 in 1983, A1 in 1984 then downgraded to Baa1 in 1988	Maine Yankee / VT Yankee / Pilgram / Seabrook
Ohio Edison	1975-1988	Aa2 FMB downgraded to A2 in 1976, downgraded to Baa3 in 1981; upgraded to Baa2 in 1987	Davis-Besse / Perry
Pacific Gas & Electric	1983-1988	A1 FMB	Diablo Canyon
Philadelphia Electric Company	1973-1991	Aaa FMB downgraded to aa2 in 1973 to A2 in 1974 to Baa2 in 1981 and Baa3 in 1983 followed by upgrade to Baa2 in 1991	Peach Bottom / Limerick
PPL Electric Utilities	1982-1986	Aa2 FMB downgraded to Aa3 and again to A2 in 1982	Susquehanna
Progress Energy Carolinas	1970-1987	Aa2 FMB downgraded to A2 in 1971 to Baa2 in 1975 followed by upgrade to A2 in 1978	Robinson / Brunswick / Shearon Harris
Progress Energy Florida	1975-1981	A2 FMB	Crystal River
Public Service Co of Colorado	1976-1990	Aa2 FMB downgraded to A2 in 1980, upgraded to A1 in 1983, upgraded to Aa3 in 1985, downgraded to A1 in 1986 and to A2 in 1987 and A3 in 1990	Ft St Vrain
Public Service Co of New Hampshire	1980-1991	Baa2 FMB downgraded to Baa3 then Ba1 in 1982, to B3 in 1984 followed by upgrade to B1 in 1986 then downgrade to Caa2 in 1987 followed by upgrade to Baa2 in 1991 exiting from bankruptcy	Seabrook
Public Service Electric & Gas	1973-1987	Aa2 FMB downgraded to Aa3 in 1982	Peach Bottom / Salem / Hope Creek
Puget Sound Energy	1978-1986	Baa2 FMB upgraded to A3 in 1985	Pebble Springs
Rochester Gas & Electric	1969-1975	Aa2 FMB downgraded to A2 in 1969	Ginna
South Carolina Electric & Gas	1979-1985	A2 FMB upgraded to A1 in 1984	Summer
Southern California Edison	1979-1985	Aa2 FMB	San Onofre
Texas Utilities	1989-1995	Baa2 FMB downgraded to Baa3 in 1990	Comanche Peak
Toledo Edison	1977-1988	Baa2 FMB upgraded to Baa1 in 1982, downgraded to Baa2 in 1983, downgraded to Baa3 in 1984	Davis-Besse / Perry
Union Electric	1980-1988	A2 FMB downgraded to Baa1 in 1980, to Baa2 in 1982, followed by upgrade to A3 in 1985 and A2 in 1988	Callaway
Virginia Electric and Power	1971-1982	Aa2 FMB downgraded to A2 in 1974	Surry / North Anna
Wisconsin Public Service	1969-1975	Aa2 FMB downgraded to A2 1969, upgraded to Aa2 in 1975	Point Beach / Kewaunee

Moody's Related Research

Special Comments:

- New Nuclear generating Capacity: Potential Credit Implications for U.S. Investor Owned Utilities, May 2008 (109152)
- EU Climate Change Strategy, May 2008 (108846)
- Decommissioning and Waste Costs for New Generation of Nuclear Power Structures, May 2008 (109086)
- Moody's Analytical Adjustments for Nuclear Energy Liabilities in EMEA, December 2007 (106604)
- Credit Challenges Ahead For Public Power: Difficult Decisions on New Generation Capacity, November 2007 (105997)
- New Nuclear Generation in the United States: Keeping Options Open vs Addressing An Inevitable Necessity, October 2007 (104977)
- Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector, August 2007 (103941)
- Environmental Regulations Increase Capital Costs for Public Power Electric Utilities, June 2007 (103616)
- Regulation Of Greenhouse Gases: Substantial Credit Challenges Likely Ahead For U.S. Public Power Electric Utilities, June 2007 (103356)
- Regulatory Pressures Increase For U.S. Electric Utilities, March 2007 (102322)
- Moody's Comments on the Back to Basics Strategy for the North American Electric Utility Sector, November 2006 (100660)

To access this report, click on the entry above. Note that this reference is current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

New Nuclear Generation: Ratings Pressure Increasing

Report Number: 117883

Author	Associate Analysts	Editor	Senior Production Associate
Jim Hempstead	Mitchell Moss Jie (Julie) Jiang	Jeff Pruzan	Judy Torre

Moody's Investors Service

FitchRatings
KNOW YOUR RISK

U.S. Electric and Gas Financial Peer Study

June 2009

FitchRatings
KNOW YOUR RISK

Corporates

Analysts

Robert Hornick
+1 212 908-0523
robert.hornick@fitchratings.com

Philippe Beard
+1 212 908-0242
philippe.beard@fitchratings.com

Inside **Page**

Overview

Fitch Ratings' "U.S. Electric and Gas Financial Peer Study" presents comparative financial ratios, as of Dec. 31, 2008, for 170 companies divided into five peer groups. The peer groups consist of utility parent companies (UPC), integrated electric utility operating companies (IUC), electric and gas utility distribution companies (UDC), midstream gas companies (MID) and competitive generating companies (CGC). A more detailed explanation of the five categories appears in the table on page 3. Within each peer group, the companies are grouped by their issuer default rating (IDR).

The data indicates that leverage measures for state-regulated utilities increased moderately in 2008. The rise was evident for both the IUC and UDC peer groups and is reflective of higher capital expenditures, primarily for infrastructure improvements, and in the case of the IUC group, environmental upgrades, as well as increased working capital requirements, largely related to higher fuel and power procurement costs, which peaked in August 2008 and have since subsided, and increases in accounts receivable and uncollectible accounts. Despite the rise in leverage, interest coverage ratios were only moderately lower, indicating the majority of utilities were able to fund at reasonable rates with little change in the embedded cost of debt despite difficult capital market conditions. The rise in capital expenditures should moderate in 2009 as a number of utilities have responded to recessionary pressures with reductions in capital spending plans in 2009 and beyond, but will remain at elevated levels that will continue to place upward pressure on leverage. The reduction in commodity prices since the August 2008 peak should ease working capital requirements if sustained throughout the year, although lower commodity prices could increase collateral postings for companies reliant on long-term power purchases.

For the third consecutive year, credit quality measures for the CGC group improved in 2008, albeit more modestly than prior years. Fitch attributes the improved financial performance to higher realized margins on energy sales for the majority of 2008, and hedging activities that locked in favorable pricing, which more than offset a decline in power prices in the fourth quarter. Fitch expects 2009 to be a challenging year for the CGC group, and the sector outlook is negative. Fitch anticipates that lower demand for electricity in 2009 as a result of the U.S. and global economic slowdown, combined with a continuation of lower natural gas prices, will lead to lower energy margins. The impact on individual companies will depend to a large degree on their hedging positions. Companies that are unhedged or have substantial hedges rolling off in 2009 will be more adversely affected than those companies with hedges that were put in place during the first half of 2008 and extend beyond 2009.

Credit quality of the MID peer group also improved in 2008, largely due to the strong commodity prices that persisted for much of the year before falling off in the fourth quarter. Similar to the CGC group, credit quality measures in 2009 are likely to be adversely affected by a continuation of lower natural gas prices expected for the remainder of 2009.

Using the Data

This study is intended to be used as an analytical tool to compare the relative financial performance of companies within, and between, rating categories. The peer study is not intended to be predictive of rating changes, since financial ratios in isolation do not determine credit ratings. Fitch's credit criteria incorporate a variety of other quantitative and qualitative factors. In addition, ratings are also materially affected by linkage to affiliates, different levels of business risk and other qualitative factors. While the peer study includes a table showing median financial ratios for each rating category within the five peer groups, these should not be construed as target ratios for the rating category. The medians reflect a single point in time, and in many cases are based on a small sampling.

In reading this report, it is important to note that the financial ratios, other than return on average common equity, are calculated on an adjusted basis. As in previous peer studies, Fitch adjusted the financial ratios to exclude nonrecurring items such as restructuring charges, asset impairments and nonrecurring gains and losses. Financial ratios have also been adjusted to exclude the effect of issuing utility tariff bonds, sometimes referred to as transition bonds or rate reduction bonds, where the instruments are serviced through a dedicated revenue stream (see note on page 19). Of the 170 companies included in the peer study, 37 are affected by these adjustments. These companies are footnoted. In many instances, debt is also adjusted to include off-balance-sheet debt or debt equivalents or to exclude non-recourse debt. It is also important to note that Fitch's definition of EBIT and EBITDA excludes non-operating income.

Several other adjustments were made in calculating the financial ratios. Interest expense is calculated before any credit for allowance for borrowed funds used during construction (AFUDC) and/or capitalized interest. Funds from operations (FFO) is defined as cash from operations, as reported, before changes in working capital. Debt ratios include on-balance-sheet leases, including those that may be reported as other liabilities and only detailed in footnotes. For further explanation of the financial ratios in this report, please refer to the definitions on pages 18 to 19.

Lastly, financial ratios are adjusted to reflect the equity credit attributed to hybrid securities, which may be reported as either debt or preferred stock. (For more information, please refer to Fitch's criteria report, "Equity Credit for Hybrid & Other Capital Securities," dated June 25, 2008, and available at www.fitchratings.com.)

Peer Group Descriptions

Peer Group	Acronym	Explanation
Utility Parent Companies	UPC	The utility parent companies peer group includes both pure holding companies and parent operating companies with one or more diversified subsidiaries. The business risk profiles of utility parent companies remain widely disparate, which often accounts for the rating discrepancy among companies with similar ratios. On the low end of the risk spectrum are utility parent companies that own one or more pure distribution companies with no commodity price risk, such as NSTAR and Consolidated Edison, Inc. At the high end of the risk spectrum are parent companies that derive a significant portion of earnings before interest and taxes (EBIT) from non-regulated businesses, which generally have greater earnings volatility.
Integrated Electric Utility Operating Companies	IUC	Integrated electric utility companies are those that continue to own both electric generation assets and a distribution network within a single legal entity. The distribution network may provide electric service only or may be a combination of electric and gas. While the distribution networks continue to be state-regulated, that is not necessarily the case for generation assets. In some jurisdictions, the generation assets have been deregulated, but have not been transferred to a separate subsidiary.
Utility Distribution Companies	UDC	The utility distribution peer group includes a mix of electric, gas and combined electric and gas delivery systems. The electric distribution companies in this peer group include pure delivery companies with no supply obligation and others that may retain the provider of last resort (POLR) obligations. Within this group, companies that retain the POLR obligation and have fixed tariffs have the highest risk profile. Gas distribution companies that are not pure delivery systems generally have commodity pass-through mechanisms. The pass-through will usually reduce the level of business risk.
Midstream Gas Companies	MID	Midstream gas companies are generally interstate pipeline companies that are regulated by the Federal Energy Regulatory Commission (FERC). One notable exception is DCP Services Midstream LLC, which gathers, processes and produces natural gas and transports, markets and stores natural gas liquids.
Competitive Generating Companies	CGC	The competitive generating companies are entities that derive the majority of EBIT from wholesale electric generation, including affiliates of regulated utilities, or other non-regulated businesses.

Source: Fitch Ratings.

Peer Medians by Rating Category

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
Utility Parent Companies												
A+	4.8	6.8	5.3	2.9	21.7	4.6	47.3	1.0	51.7	(4.4)	8.8	11.5
A	3.7	5.3	5.6	3.6	22.2	4.5	56.0	0.8	43.5	41.9	11.4	13.6
A–	4.0	5.5	3.9	4.0	14.0	7.1	58.6	0.2	41.2	53.7	14.9	13.1
BBB+	3.5	4.8	4.8	3.7	21.4	4.7	53.0	0.9	45.3	63.9	20.8	17.3
BBB	2.4	4.1	3.9	4.7	15.4	6.5	60.6	0.2	39.2	28.0	14.8	9.2
BBB–	2.3	3.7	3.9	4.6	14.0	7.1	61.2	—	38.1	63.6	16.5	8.1
BB+	2.0	3.5	3.2	4.9	13.0	7.7	70.6	2.3	26.5	54.5	11.4	12.6
BB	0.2	1.2	1.9	13.9	5.6	17.8	57.8	1.9	38.0	8.7	1.9	(16.2)
BB–	1.7	2.5	2.7	6.5	10.5	9.5	62.8	—	37.2	23.2	15.6	6.8
B	0.7	1.1	1.3	10.9	2.2	44.9	105.5	—	(9.0)	49.7	20.4	(624.0)
Utility Distribution Companies												
A+	5.6	8.2	7.4	2.7	30.2	3.4	47.1	1.0	51.4	58.6	15.8	13.4
A	3.2	7.5	5.9	4.1	15.9	6.3	65.0	—	35.0	(53.5)	4.0	9.2
A–	3.3	4.8	4.7	4.1	22.8	4.4	47.9	—	52.1	52.9	9.5	10.1
BBB+	3.2	4.7	4.4	3.9	20.9	4.8	49.0	0.3	48.8	28.0	11.3	9.2
BBB	3.0	4.7	3.9	3.5	18.7	5.4	54.8	0.4	44.1	50.1	10.9	9.3
BBB–	2.8	4.2	3.9	4.1	17.3	5.8	53.0	—	45.4	44.5	12.0	5.6
BB+	2.4	4.8	3.8	3.4	19.0	5.3	49.5	—	50.5	96.8	19.7	9.3
Integrated Utility Companies												
A+	4.0	6.1	5.6	3.2	23.9	4.2	47.1	1.0	51.9	18.0	12.9	11.3
A	4.5	6.5	5.7	3.3	23.4	4.3	52.0	1.1	46.6	48.5	16.9	12.0
A–	3.7	5.7	5.4	3.2	25.6	3.9	51.7	0.6	46.3	52.1	14.5	12.3
BBB+	4.4	6.3	5.5	3.1	25.6	3.9	51.6	0.6	47.1	47.9	18.3	12.1
BBB	2.6	4.0	4.1	4.0	19.2	5.2	53.6	0.1	46.4	47.4	12.6	8.9
BBB–	2.5	4.2	4.2	4.0	22.3	4.5	53.9	1.4	44.0	66.8	12.6	8.6
BB+	1.9	2.9	1.9	5.8	5.5	(1.5)	57.9	0.1	42.0	68.4	7.5	8.6
BB	1.8	2.6	3.2	5.3	14.8	6.7	56.4	—	41.9	45.0	9.9	6.0
Midstream Companies												
BBB+	8.0	9.7	9.0	1.8	45.6	2.2	65.4	—	29.1	(11.7)	10.2	79.2
BBB	3.5	4.7	4.4	4.1	19.6	5.1	53.6	—	46.4	52.9	32.7	13.1
BBB–	3.3	4.1	4.6	3.2	28.6	3.5	40.9	—	59.1	64.7	38.8	14.1
BB+	2.5	3.9	3.4	4.4	14.1	7.3	67.8	1.5	19.4	67.6	29.2	(40.4)
Competitive Generation Companies												
BBB+	7.6	8.6	7.5	2.1	41.1	2.6	48.0	—	52.0	132.0	27.7	27.9
BBB	4.4	5.4	4.3	3.4	18.1	5.5	54.6	—	45.3	25.3	21.3	15.4
BBB–	3.3	5.3	5.8	2.9	32.4	3.1	59.7	—	37.7	112.0	35.7	30.7
BB+	2.3	2.6	(0.6)	3.8	(16.3)	(6.1)	42.7	—	56.8	(3,875.0)	22.4	(15.7)
BB	9.0	10.9	9.8	1.7	49.1	2.0	26.9	—	73.1	292.2	39.0	13.5
BB–	1.8	2.2	2.7	6.4	12.7	7.9	71.0	—	28.1	132.1	30.8	21.8
B+	3.6	4.1	2.8	3.0	17.2	6.3	56.7	—	36.5	87.8	30.8	32.0
B	1.5	2.3	2.2	5.3	9.8	12.0	55.8	—	42.8	55.5	19.0	4.2

EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations.

Alphabetical Company Listing

Company Name	Group	IDR Rating	Page
AEP Texas Central Company	UDC	BBB	11
AEP Texas North Company	UDC	BBB+	11
AES Corporation	CGC	B+	14
AGL Resources, Inc.	UPC	A–	7
Alabama Power Company	IUC	A	9
Allegheny Energy Supply Company, LLC	CGC	BBB–	14
Allegheny Energy, Inc.	UPC	BBB–	8
Ameren Corporation	UPC	BBB+	7
Ameren Energy Generating Company	CGC	BBB+	14
American Electric Power Co., Inc.	UPC	BBB	7
Appalachian Power Company	IUC	BBB	9
Arizona Public Service Company	IUC	BBB–	10
Atlantic City Electric Company	UDC	BBB	11
Atmos Energy Corp.	UDC	BBB	11
Avista Corporation	IUC	BBB–	10
Baltimore Gas and Electric Company	UDC	BBB+	11
Berkshire Gas Company	UDC	BBB+	11
Black Hills Corp.	UPC	BBB	7
Black Hills Power, Inc.	IUC	BBB	9
Brookfield Renewable Power Inc.	CGC	BBB–	14
CILCORP Inc.	UPC	BBB–	8
CMS Energy Corporation	UPC	BB+	8
Carolina Power & Light Company	IUC	A–	9
CenterPoint Energy Houston Electric LLC	UDC	BBB	11
CenterPoint Energy Resources Corp.	MID	BBB	13
CenterPoint Energy, Inc.	UPC	BBB–	8
Central Hudson Gas & Electric Corp.	UDC	A–	11
Central Illinois Light Company	IUC	BBB	9
Central Illinois Public Service Company	UDC	BBB–	12
Central Maine Power Company	UDC	BBB+	11
Cleveland Electric Illuminating Company	UDC	BB+	12
Colorado Interstate Gas Company	MID	BBB–	13
Columbus Southern Power Company	IUC	BBB+	9
Commonwealth Edison Company	UDC	BB+	12
Connecticut Light & Power Company	UDC	BBB	11
Connecticut Natural Gas Corporation	UDC	BBB+	11
Consolidated Edison Company of New York, Inc.	UDC	BBB+	11
Consolidated Edison, Inc.	UPC	BBB+	7
Constellation Energy, Inc.	UPC	BBB	7
Consumers Energy Company	IUC	BBB–	10
DCP Midstream, LLC	MID	BBB+	13
DPL Inc.	UPC	BBB+	7
DTE Energy Company	UPC	BBB	7
Dayton Power & Light Company	IUC	A–	9
Delmarva Power & Light Company	UDC	BBB+	11

UDC – Utility distribution company. CGC – Competitive generating company. UPC – Utility parent company. IUC – Integrated utility company. MID – Midstream gas company.
Source: Fitch Ratings.

Company Name	Group	IDR Rating	Page
Detroit Edison Company	IUC	BBB	9
Dominion Resources, Inc.	UPC	BBB+	7
Dynegy Holdings Inc.	CGC	B	14
Dynegy Inc.	CGC	B	14
Edison International	UPC	BBB–	8
Edison Mission Energy	CGC	BB–	14
El Paso Corporation	MID	BB+	13
El Paso Natural Gas Company	MID	BBB–	13
Empire District Electric Company	IUC	BBB–	10
Energy East Corporation	UPC	BBB	7
Energy Future Holdings Corporation	UPC	B	8
Entergy Arkansas, Inc.	IUC	BBB–	10
Entergy Corporation	UPC	BBB–	8
Entergy Gulf States, Inc.	IUC	BB+	10
Entergy Louisiana, LLC	IUC	BBB–	10
Entergy Mississippi, Inc.	IUC	BBB–	10
Entergy New Orleans, Inc.	IUC	BB	10
Entergy Texas, Inc.	IUC	BB+	10
Exelon Corporation	UPC	BBB+	7
Exelon Generation Company, LLC	CGC	BBB+	14
FPL Group, Inc.	UPC	A	7
FirstEnergy Corp.	UPC	BBB	7
Florida Power & Light Company	IUC	A	9
Florida Power Corporation	IUC	A–	9
Georgia Power Company	IUC	A	9
Gulf Power Company	IUC	A–	9
IDACORP, Inc.	UPC	BBB	7
IPALCO Enterprises, Inc.	UPC	BBB–	8
Idaho Power Co.	IUC	BBB	9
Illinois Power Company	UDC	BBB–	12
Indiana Michigan Power Company	IUC	BBB–	10
Indianapolis Power & Light Company	IUC	BBB–	10
Jersey Central Power & Light Co.	UDC	BBB	11
Kentucky Power Company	IUC	BBB–	10
Knight Inc.	MID	BB+	13
Laclede Gas Company	UDC	A–	11
Laclede Group, Inc. (The)	UPC	A–	7
MDU Resources Group, Inc.	UPC	A–	7
Metropolitan Edison Company	UDC	BBB–	12
Michigan Consolidated Gas Company	UDC	BBB–	12
MidAmerican Energy Company	IUC	A–	9
MidAmerican Energy Holdings Company	UPC	BBB+	7
Midwest Generation LLC	CGC	BB	14
Mirant Corporation	CGC	B+	14
Mississippi Power Company	IUC	A+	9

UDC – Utility distribution company. CGC – Competitive generating company. UPC – Utility parent company. IUC – Integrated utility company. MID – Midstream gas company. *Continued on next page.*
Source: Fitch Ratings.

Alphabetical Company Listing (Continued)

Company Name	Group	IDR Rating	Page
NRG Energy, Inc.	CGC	B	14
NSTAR	UPC	A–	7
NSTAR Electric	UDC	A+	11
NV Energy, Inc.	UPC	BB–	8
National Fuel Gas Company	UPC	A–	7
Nevada Power Company d/b/a NV Energy	IUC	BB	10
New York State Electric & Gas Corp.	UDC	BBB	11
NiSource Inc.	UPC	BBB–	8
Nicor Gas Company	UDC	A	11
Nicor Inc.	UPC	A	7
NorthWestern Corporation	IUC	BBB–	10
Northeast Utilities	UPC	BBB	7
Northern States Power Company — MN	IUC	A–	9
Northern States Power Company — WI	IUC	A–	9
Northwest Pipeline Corporation	MID	BBB	13
OGE Energy Corp.	UPC	A	7
Ohio Edison Company	UDC	BBB–	12
Ohio Power Company	IUC	BBB	9
Oklahoma Gas & Electric Company	IUC	A+	9
Oncor Electric Delivery Company	UDC	BBB–	12
Orange & Rockland Utilities, Inc.	UDC	A–	11
PECO Energy Company	UDC	BBB+	11
Pepco Holdings, Inc.	UPC	BBB	7
PNM Resources Inc.	UPC	BB	8
PPL Corporation	UPC	BBB	7
PPL Electric Utilities Corporation	UDC	BBB	11
PPL Energy Supply LLC	CGC	BBB	14
PSEG Energy Holdings L.L.C.	CGC	BB+	14
PSEG Power LLC	CGC	BBB+	14
PacifiCorp	IUC	BBB	9
Pacific Gas & Electric Company	IUC	A–	9
Panhandle Eastern Pipe Line Company	MID	BBB	13
Pennsylvania Electric Company	UDC	BBB–	12
Pinnacle West Capital Corporation	UPC	BBB–	8
Potomac Electric Power Company	UDC	BBB+	11
Progress Energy Inc.	UPC	BBB	7
Public Service Company of New Mexico	IUC	BB	10
Public Service Company of Oklahoma	IUC	BBB	9
Public Service Company of Colorado	IUC	BBB+	9
Public Service Company of New Hampshire	IUC	BBB	9

UPC – Utility parent company. IUC – Integrated utility company. MID – Midstream gas company.
Source: Fitch Ratings.

Company Name	Group	IDR Rating	Page
Public Service Company of North Carolina, Incorporated	UDC	A–	11
Public Service Electric & Gas Company	UDC	BBB+	11
Public Service Enterprise Group Incorporated	UPC	BBB+	7
RRI Energy, Inc.	CGC	B	14
Rochester Gas & Electric Corp.	UDC	BBB–	12
SCANA Corporation	UPC	A–	7
San Diego Gas & Electric Co.	UDC	A+	11
Sempra Energy	UPC	A	7
Sierra Pacific Power Company d/b/a NV Energy	IUC	BB	10
South Carolina Electric & Gas Co.	IUC	A–	9
Southern California Edison Co.	IUC	A–	9
Southern California Gas Company	UDC	A+	11
Southern Company	UPC	A	7
Southern Connecticut Gas Company	UDC	BBB+	11
Southern Natural Gas Company	MID	BBB–	13
Southern Power Company	CGC	BBB+	14
Southern Union Company	MID	BBB–	13
Southwest Gas Corporation	UDC	BBB	11
Southwestern Electric Power Company	IUC	BBB	9
Southwestern Public Service Company	IUC	BBB	9
Spectra Energy Capital, LLC	MID	BBB	13
System Energy Resources Inc.	CGC	BBB–	14
TECO Energy, Inc.	UPC	BBB–	8
Tampa Electric Company	IUC	BBB	9
Tennessee Gas Pipeline Company	MID	BBB–	13
Texas-New Mexico Power Company	UDC	BB+	12
Toledo Edison Company	UDC	BB+	12
Transcontinental Gas Pipe Line Corp.	MID	BBB	13
Tucson Electric Power Company	IUC	BB	10
UGI Utilities, Inc.	UDC	A–	11
Union Electric Company	IUC	BBB+	9
Virginia Electric and Power Company	IUC	BBB+	9
WGL Holdings, Inc.	UPC	A+	7
Washington Gas Light Company	UDC	A+	11
Westar Energy, Inc.	IUC	BBB–	10
Western Massachusetts Electric Company	UDC	BBB	11
Williams Companies, Inc.	MID	BBB–	13
Wisconsin Electric Power Company	IUC	A	9
Wisconsin Energy Corporation	UPC	A–	7
Xcel Energy, Inc.	UPC	BBB+	7

UDC – Utility distribution company. CGC – Competitive generating company. UPC – Utility parent company. IUC – Integrated utility company. MID – Midstream gas company.
Source: Fitch Ratings.

Utility Parent Companies

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
A+ IDR												
WGL Holdings, Inc.	4.8	6.8	5.3	2.9	21.7	4.6	47.3	1.0	51.7	(4.4)	8.8	11.5
Median	4.8	6.8	5.3	2.9	21.7	4.6	47.3	1.0	51.7	(4.4)	8.8	11.5
A IDR												
FPL Group, Inc.[a]	3.3	4.8	4.9	3.5	22.9	4.4	51.4	7.1	41.5	116.6	17.1	14.6
Nicor Inc.	4.6	8.9	7.0	3.5	19.2	5.2	56.0	—	44.0	(44.4)	4.9	12.5
OGE Energy Corp.	3.7	5.5	6.4	3.6	27.4	3.6	56.5	—	43.5	41.9	11.3	12.9
Sempra Energy	3.4	5.3	5.6	3.9	22.2	4.5	47.3	0.8	50.3	17.5	11.4	13.7
Southern Company	3.7	5.2	4.9	3.8	20.0	5.0	56.7	3.0	40.3	53.4	20.5	13.6
A Median	3.7	5.3	5.6	3.6	22.2	4.5	56.0	0.8	43.5	41.9	11.4	13.6
A– IDR												
AGL Resources, Inc.	4.2	5.5	3.9	4.0	13.3	7.5	60.1	—	39.1	27.7	17.1	13.1
Laclede Group, Inc. (The)	3.8	5.0	3.8	4.1	13.4	7.5	55.5	—	44.5	(121.3)	5.0	17.1
MDU Resources Group, Inc.	7.5	11.8	10.9	1.7	48.5	2.1	38.9	0.2	60.8	90.8	13.0	11.1
NSTAR[a]	4.0	5.8	5.4	3.6	21.1	4.7	58.9	0.7	40.4	57.1	15.9	13.6
National Fuel Gas Company	6.4	8.6	8.2	1.7	49.7	2.0	40.7	—	59.3	95.2	20.3	16.6
SCANA Corporation	2.9	4.2	3.7	4.5	14.0	7.1	59.6	1.1	39.3	28.2	13.3	11.5
Wisconsin Energy Corporation	2.7	4.1	3.7	4.8	13.8	7.3	58.6	0.3	41.2	53.7	14.9	11.2
A– Median	4.0	5.5	3.9	4.0	14.0	7.1	58.6	0.2	41.2	53.7	14.9	13.1
BBB+ IDR												
Ameren Corporation[a]	3.3	4.8	4.9	3.9	20.4	4.9	52.4	1.0	46.5	49.2	17.5	8.8
Consolidated Edison, Inc.	2.9	4.2	3.7	4.3	14.8	6.8	50.7	0.8	48.5	—	12.2	12.7
DPL Inc.	4.4	5.8	5.2	2.7	27.1	3.7	61.1	0.7	38.2	100.0	27.2	26.5
Dominion Resources, Inc.	3.8	4.8	4.7	3.5	21.6	4.6	60.3	3.6	36.2	48.6	22.9	18.8
Exelon Corporation[a]	6.8	8.1	7.4	1.9	41.8	2.4	50.8	1.5	47.7	135.4	28.6	25.8
MidAmerican Energy Holdings Company	2.1	3.0	2.9	5.1	12.7	7.9	66.0	0.3	33.2	65.7	22.3	18.9
Public Service Enterprise Group Incorporated[a]	4.8	5.9	5.0	2.4	27.8	3.6	49.1	0.4	50.5	86.0	19.2	15.8
Xcel Energy, Inc.	2.5	4.0	4.2	3.8	21.1	4.7	53.6	2.4	44.0	62.1	12.4	9.7
BBB+ Median	3.5	4.8	4.8	3.7	21.4	4.7	53.0	0.9	45.3	63.9	20.8	17.3
BBB IDR												
American Electric Power Co., Inc.[a]	2.7	4.2	3.9	4.4	15.9	6.3	61.0	0.2	38.9	47.1	17.3	13.3
Black Hills Corp.	2.8	4.7	5.4	4.7	19.9	5.0	53.5	—	46.5	28.0	14.8	10.4
Constellation Energy, Inc.[a]	2.4	3.8	1.8	5.2	3.9	25.7	65.9	5.9	28.0	(85.5)	4.6	(31.2)
DTE Energy Company[a]	2.4	4.2	4.9	4.1	22.3	4.5	54.7	1.6	43.4	78.4	11.6	9.2
Energy East Corporation	2.0	3.0	2.5	5.3	9.7	10.3	60.6	0.3	39.2	12.6	11.4	1.5
FirstEnergy Corp.[a]	3.4	5.5	4.1	3.2	17.4	5.8	63.9	—	36.1	51.0	20.9	15.6
IDACORP, Inc.	2.4	3.7	3.1	4.9	11.8	8.5	52.2	—	47.8	33.6	19.8	7.8
Northeast Utilities[a]	2.3	4.1	3.3	5.0	11.1	9.0	61.7	0.1	38.2	22.9	9.8	8.8
Pepco Holdings, Inc.[a]	2.4	3.5	4.4	5.0	19.4	5.2	56.7	0.1	43.2	20.4	7.0	7.3
PPL Corporation[a]	4.1	5.2	4.0	3.8	15.4	6.5	61.8	1.6	36.5	55.7	23.3	17.5
Progress Energy Inc.	2.5	3.7	3.6	4.7	14.6	6.8	57.7	0.3	41.9	24.7	18.4	9.7
BBB Median	2.4	4.1	3.9	4.7	15.4	6.5	60.6	0.2	39.2	28.0	14.8	9.2

[a]Excludes debt, revenue, amortization and interest expense associated with the issue of utility tariff bonds, sometimes referred to as rate reduction bonds or securitization bonds. EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations. *Continued on next page.*

Source: Fitch Ratings, company reports.

Utility Parent Companies (Continued)

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
BBB– IDR												
Allegheny Energy, Inc.[a]	3.3	4.0	3.9	3.9	18.5	5.4	56.5	—	43.4	66.5	24.0	14.7
CILCORP Inc.	2.1	3.6	3.9	6.0	13.4	7.5	61.2	0.7	38.1	57.7	10.5	5.7
CenterPoint Energy, Inc.[a]	2.3	3.5	3.9	4.8	17.5	5.7	79.9	—	20.1	43.7	10.3	23.2
Edison International	3.0	4.4	3.4	3.8	14.0	7.2	59.1	3.4	36.5	64.0	19.1	13.5
Entergy Corporation[a]	3.6	5.2	6.2	3.5	28.5	3.5	57.0	3.6	39.4	122.3	17.4	15.4
IPALCO Enterprises, Inc.	1.9	3.0	2.7	4.1	14.0	7.1	98.0	2.5	(0.6)	100.9	24.4	(676.2)
NiSource Inc.	2.3	3.7	3.6	5.1	13.6	7.3	61.6	—	38.4	34.4	10.3	1.6
Pinnacle West Capital Corporation	2.3	3.9	4.8	4.6	20.9	4.8	55.6	—	44.4	63.6	16.5	6.9
TECO Energy, Inc.	1.7	2.8	2.7	5.1	12.1	8.2	62.2	—	37.8	37.6	11.4	8.1
BBB– Median	2.3	3.7	3.9	4.6	14.0	7.1	61.2	—	38.1	63.6	16.5	8.1
BB+ IDR												
CMS Energy Corporation[a]	2.0	3.5	3.2	4.9	13.0	7.7	70.6	2.3	26.5	54.5	11.4	12.6
BB+ Median	2.0	3.5	3.2	4.9	13.0	7.7	70.6	2.3	26.5	54.5	11.4	12.6
BB IDR												
PNM Resources, Inc.	0.2	1.2	1.9	13.9	5.6	17.8	57.8	1.9	38.0	8.7	1.9	(16.2)
BB Median	0.2	1.2	1.9	13.9	5.6	17.8	57.8	1.9	38.0	8.7	1.9	(16.2)
BB– IDR												
NV Energy, Inc.	1.7	2.5	2.7	6.5	10.5	9.5	62.8	—	37.2	23.2	15.6	6.8
BB– Median	1.7	2.5	2.7	6.5	10.5	9.5	62.8	—	37.2	23.2	15.6	6.8
B IDR												
Energy Future Holdings Corporation[a]	0.7	1.1	1.3	10.9	2.2	44.9	105.5	—	(9.0)	49.7	20.4	(624.0)
B Median	0.7	1.1	1.3	10.9	2.2	44.9	105.5	—	(9.0)	49.7	20.4	(624.0)

[a]Excludes debt, revenue, amortization and interest expense associated with the issue of utility tariff bonds, sometimes referred to as rate reduction bonds or securitization bonds. EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations.
Source: Fitch Ratings, company reports.

Integrated Utility Companies

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
A+ IDR												
Mississippi Power Company	4.7	7.0	5.8	2.8	24.5	4.1	48.1	2.0	50.0	15.7	11.6	13.8
Oklahoma Gas & Electric Company	3.3	5.2	5.4	3.6	23.3	4.3	46.1	—	53.9	20.4	14.2	8.8
A+ Median	4.0	6.1	5.6	3.2	23.9	4.2	47.1	1.0	51.9	18.0	12.9	11.3
A IDR												
Alabama Power Company	4.2	6.0	5.5	3.3	22.5	4.4	52.2	5.3	42.5	43.7	20.9	13.3
Florida Power & Light Company*	4.7	7.0	6.7	2.5	31.8	3.1	41.5	—	58.5	93.7	12.9	10.3
Georgia Power Company	4.3	6.0	5.8	3.3	24.3	4.1	51.7	1.8	46.5	53.3	19.7	13.6
Wisconsin Electric Power Company	5.4	8.2	4.4	4.0	10.5	9.6	52.9	0.4	46.7	(1.0)	14.1	10.7
A Median	4.5	6.5	5.7	3.3	23.4	4.3	52.0	1.1	46.6	48.5	16.9	12.0
A– IDR												
Carolina Power & Light Company	4.5	6.9	6.7	2.4	34.5	2.9	45.5	0.6	53.9	139.2	22.5	13.1
Dayton Power & Light Company	11.8	15.5	13.2	1.5	50.5	2.0	37.7	0.7	61.6	98.8	27.8	20.2
Florida Power Corporation	2.9	4.2	3.3	4.7	11.6	8.6	57.5	0.3	42.2	3.2	14.4	12.0
Gulf Power Company	4.1	5.9	5.4	3.6	20.3	4.9	52.7	4.4	42.9	16.1	13.8	12.6
MidAmerican Energy Company	3.7	5.5	6.3	3.8	25.1	4.0	56.2	0.4	43.4	48.5	12.5	14.1
Northern States Power Company — MN	3.1	5.1	5.4	3.0	28.0	3.6	50.2	—	49.8	54.4	13.5	9.7
Northern States Power Company — WI	3.8	6.0	5.4	2.8	26.2	3.8	48.7	—	51.3	69.9	11.6	10.0
Pacific Gas & Electric Company*	3.3	5.2	5.7	2.9	31.8	3.1	50.7	1.0	48.3	49.8	15.4	12.9
South Carolina Electric & Gas Co.	3.3	4.8	3.4	3.9	12.5	8.0	52.8	1.4	44.2	36.0	19.9	10.0
Southern California Edison Co.	3.8	6.4	4.6	3.4	16.4	6.1	55.0	5.1	37.7	54.8	14.6	10.7
A– Median	3.7	5.7	5.4	3.2	25.6	3.9	51.7	0.6	46.3	52.1	14.5	12.3
BBB+ IDR												
Columbus Southern Power Company	4.5	6.4	5.3	2.5	26.6	3.8	55.0	—	45.0	67.2	19.2	19.7
Public Service Company of Colorado	4.3	6.2	5.7	3.1	25.0	4.0	41.8	—	58.2	54.9	13.4	9.8
Union Electric Company	2.8	4.6	5.3	4.4	21.2	4.7	51.3	1.2	47.5	30.7	17.4	7.1
Virginia Electric and Power Company	4.8	6.6	6.4	3.1	26.2	3.8	51.9	1.4	46.6	40.9	23.6	14.3
BBB+ Median	4.4	6.3	5.5	3.1	25.6	3.9	51.6	0.6	47.1	47.9	18.3	12.1
BBB IDR												
Appalachian Power Company	1.4	2.6	2.6	5.9	10.6	9.5	58.5	0.2	41.2	34.9	10.8	5.5
Black Hills Power, Inc.	3.5	5.5	6.2	3.7	25.8	3.9	46.4	—	53.6	39.4	16.7	9.5
Central Illinois Light Company	6.3	10.0	9.6	3.0	29.1	3.4	47.6	1.1	51.3	65.2	11.5	10.7
Detroit Edison Company*	3.2	6.0	5.6	3.1	24.7	4.0	54.3	—	45.7	88.5	15.6	9.7
Idaho Power Co.	2.5	3.8	4.1	4.7	17.0	5.9	53.7	—	46.3	27.0	19.8	8.2
Ohio Power Company	2.5	3.8	3.3	4.1	14.2	7.0	56.4	0.2	43.0	68.7	16.0	9.8
PacifiCorp	2.8	4.2	4.3	3.9	20.0	5.0	48.7	0.3	51.1	55.3	21.1	8.3
Public Service Company of Oklahoma	2.0	3.4	3.7	3.6	22.6	4.4	56.0	0.2	43.8	58.4	9.7	11.2
Public Service Company of New Hampshire*	3.1	5.1	4.2	4.3	14.9	6.7	53.6	—	46.4	34.3	9.9	9.9
Southwestern Electric Power Company	1.5	2.8	4.2	4.7	24.2	4.1	54.3	0.1	45.6	31.5	11.1	8.4
Southwestern Public Service Company	1.7	3.4	3.5	4.8	14.9	6.7	52.4	—	47.6	62.9	5.3	3.7
Tampa Electric Company	2.8	4.5	3.6	3.2	18.4	5.4	48.0	—	52.0	36.5	13.7	8.4
BBB Median	2.6	4.0	4.1	4.0	19.2	5.2	53.6	0.1	46.4	47.4	12.6	8.9

*Excludes debt, revenue, amortization and interest expense associated with the issue of utility tariff bonds, sometimes referred to as rate reduction bonds or securitization bonds. EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations. *Continued on next page.*

Source: Fitch Ratings, company reports.

Integrated Utility Companies (Continued)

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
BBB– IDR												
Arizona Public Service Company	2.7	4.5	5.5	3.9	25.6	3.9	53.0	—	47.0	65.0	18.3	7.8
Avista Corporation	2.3	3.5	3.9	4.1	20.3	4.9	51.0	3.9	45.1	35.0	11.0	7.7
Consumers Energy Company[a]	3.2	5.5	6.2	3.3	29.1	3.4	53.2	0.4	46.3	68.7	11.8	9.9
Empire District Electric Company	2.0	3.3	3.6	4.8	16.4	6.1	55.1	3.0	41.9	23.5	17.4	7.5
Entergy Arkansas, Inc.	2.4	5.1	6.7	4.0	28.0	3.6	54.4	2.7	42.9	112.0	8.8	2.9
Entergy Louisiana, LLC	2.7	4.8	11.6	3.3	67.2	1.5	46.9	2.4	50.7	187.5	8.2	9.9
Entergy Mississippi, Inc.	2.9	4.6	4.3	3.3	21.4	4.7	50.4	2.7	46.9	19.0	9.2	8.6
Indiana Michigan Power Company	2.2	3.1	4.1	5.5	18.3	5.5	63.5	0.2	36.3	118.2	15.1	9.4
Indianapolis Power & Light Company	4.4	7.1	8.1	2.3	43.8	2.3	54.8	2.6	42.6	98.1	24.4	16.2
Kentucky Power Company	1.9	3.2	2.8	4.9	11.3	8.9	58.0	—	42.0	36.9	9.8	6.4
NorthWestern Corporation[a]	2.7	4.0	4.2	3.5	23.2	4.3	53.5	—	46.5	116.8	13.4	8.6
Westar Energy, Inc.	1.9	3.3	3.7	6.3	12.8	7.8	58.1	0.3	41.6	18.1	15.5	8.8
BBB– Median	**2.5**	**4.2**	**4.2**	**4.0**	**22.3**	**4.5**	**53.9**	**1.4**	**44.0**	**66.8**	**12.6**	**8.6**
BB+ IDR												
Entergy Gulf States, Inc.	1.9	2.9	5.2	5.8	25.0	4.0	62.2	0.2	37.5	147.4	8.9	11.0
Entergy Texas, Inc.[a]	1.9	2.8	(1.4)	5.9	(14.1)	(7.1)	53.5	—	46.5	(10.7)	6.0	6.1
BB+ Median	**1.9**	**2.9**	**1.9**	**5.8**	**5.5**	**(1.5)**	**57.9**	**0.1**	**42.0**	**68.4**	**7.5**	**8.6**
BB IDR												
Entergy New Orleans, Inc.	3.3	4.9	5.1	2.7	30.9	3.2	55.2	3.0	41.9	84.3	8.5	17.5
Nevada Power Company d/b/a NV Energy	1.8	2.6	2.9	6.3	11.6	8.6	56.4	—	43.6	18.9	15.9	6.0
Public Service Company of New Mexico	1.0	2.0	2.9	8.8	10.8	9.3	51.7	0.3	44.7	45.0	7.2	(2.3)
Sierra Pacific Power Company d/b/a NV Energy	2.3	3.4	3.5	5.1	14.8	6.7	61.4	—	38.6	(14.7)	15.3	9.7
Tucson Electric Power Company	1.0	2.4	3.2	5.3	17.3	5.8	70.1	—	29.9	92.7	9.9	0.7
BB Median	**1.8**	**2.6**	**3.2**	**5.3**	**14.8**	**6.7**	**56.4**	**—**	**41.9**	**45.0**	**9.9**	**6.0**

[a]Excludes debt, revenue, amortization and interest expense associated with the issue of utility tariff bonds, sometimes referred to as rate reduction bonds or securitization bonds. EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations.
Source: Fitch Ratings, company reports.

Utility Distribution Companies

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
A+ IDR												
NSTAR Electric[a]	6.4	9.1	7.6	2.8	25.9	3.9	45.8	0.9	53.4	71.0	17.3	11.7
San Diego Gas & Electric Co.	4.8	7.3	7.3	2.5	34.5	2.9	44.2	1.2	51.9	69.5	17.4	14.3
Southern California Gas Company	6.7	11.0	9.2	2.0	37.9	2.6	48.5	0.6	50.9	47.8	9.1	16.7
Washington Gas Light Company	4.8	6.8	5.5	2.9	22.4	4.5	49.0	1.1	49.9	(14.2)	14.3	12.4
A+ Median	**5.6**	**8.2**	**7.4**	**2.7**	**30.2**	**3.4**	**47.1**	**1.0**	**51.4**	**58.6**	**15.8**	**13.4**
A IDR												
Nicor Gas Company	3.2	7.5	5.9	4.1	15.9	6.3	65.0	—	35.0	(53.5)	4.0	9.2
A Median	**3.2**	**7.5**	**5.9**	**4.1**	**15.9**	**6.3**	**65.0**	**—**	**35.0**	**(53.5)**	**4.0**	**9.2**
A– IDR												
Central Hudson Gas & Electric Corp.	2.6	3.7	5.1	4.8	22.8	4.4	54.4	1.9	43.7	84.8	8.4	7.2
Laclede Gas Company	2.8	3.9	3.8	5.9	12.1	8.3	65.9	—	34.1	(141.8)	7.3	11.1
Orange & Rockland Utilities, Inc.	3.4	4.8	4.0	3.1	20.3	4.9	47.9	—	52.1	(16.7)	9.5	10.1
Public Service Company of North Carolina, Incorporated	3.3	4.8	6.2	4.1	26.6	3.8	43.1	—	56.9	52.9	11.8	7.0
UGI Utilities, Inc.	3.8	4.9	4.7	3.1	24.3	4.1	46.9	—	53.1	112.5	11.6	12.0
A– Median	**3.3**	**4.8**	**4.7**	**4.1**	**22.8**	**4.4**	**47.9**	**—**	**52.1**	**52.9**	**9.5**	**10.1**
BBB+ IDR												
AEP Texas North Company	2.5	4.3	4.7	3.8	22.1	4.5	55.1	0.3	44.6	26.3	21.2	10.4
Baltimore Gas and Electric Company[a]	1.4	2.9	3.9	6.0	16.6	6.0	50.7	8.8	40.1	(3.5)	4.3	2.4
Berkshire Gas Company	3.0	4.3	4.3	3.1	25.0	4.0	32.1	—	67.9	50.0	14.6	5.4
Central Maine Power Company	3.2	4.8	4.9	3.9	20.9	4.8	37.6	0.9	61.5	56.4	15.0	7.1
Connecticut Natural Gas Corporation	3.3	5.0	4.4	3.0	22.2	4.5	32.2	0.2	67.6	28.0	9.3	4.9
Consolidated Edison Company of New York, Inc.	3.3	4.7	4.3	4.0	17.9	5.6	50.4	0.9	48.8	18.5	16.0	9.2
Delmarva Power & Light Company	3.5	5.3	5.6	4.3	20.2	5.0	55.3	—	44.7	47.3	9.4	9.5
PECO Energy Company[a]	4.7	6.6	4.8	2.5	23.1	4.3	47.2	4.5	48.3	(31.6)	12.3	15.3
Potomac Electric Power Company	2.8	4.3	9.0	4.3	43.3	2.3	58.3	—	41.7	48.7	11.0	9.8
Public Service Electric & Gas Company[a]	3.6	5.4	4.3	2.9	20.7	4.8	49.0	0.8	50.2	95.9	9.2	10.4
Southern Connecticut Gas Company	2.7	3.6	3.2	4.4	13.8	7.2	37.7	—	62.3	(16.2)	11.3	3.8
BBB+ Median	**3.2**	**4.7**	**4.4**	**3.9**	**20.9**	**4.8**	**49.0**	**0.3**	**48.8**	**28.0**	**11.3**	**9.2**
BBB IDR												
AEP Texas Central Company	2.3	3.8	3.4	3.1	19.8	5.0	59.8	0.4	39.8	(8.6)	18.2	17.7
Atlantic City Electric Company[a]	3.1	4.8	3.5	3.1	16.9	5.9	54.0	0.4	45.6	46.3	8.3	12.6
Atmos Energy Corp.	3.0	4.5	4.5	3.9	20.1	5.0	54.6	—	45.4	53.8	5.9	9.0
CenterPoint Energy Houston Electric LLC[a]	3.5	6.1	5.3	2.8	24.8	4.0	54.9	—	45.1	(29.0)	25.2	12.0
Connecticut Light & Power Company[a]	2.7	5.0	3.5	4.0	12.4	8.0	53.9	1.8	44.3	18.1	10.3	9.6
Jersey Central Power & Light Co.[a]	5.3	10.9	6.7	1.6	33.7	3.0	32.5	—	67.5	95.4	12.1	6.5
New York State Electric & Gas Corp.	3.0	4.5	3.2	3.7	13.1	7.6	55.6	0.4	44.0	73.7	11.8	0.5
PPL Electric Utilities Corporation[a]	4.0	5.4	4.8	4.0	17.6	5.7	55.2	6.4	38.3	89.2	11.4	12.0
Southwest Gas Corporation	2.2	4.3	4.2	3.2	23.3	4.3	53.4	3.1	43.5	87.0	9.7	6.0
Western Massachusetts Electric Company[a]	2.6	3.8	3.6	6.0	11.2	8.9	60.5	—	39.5	17.9	9.9	7.5
BBB Median	**3.0**	**4.7**	**3.9**	**3.5**	**18.7**	**5.4**	**54.8**	**0.4**	**44.1**	**50.1**	**10.9**	**9.3**

[a]Excludes debt, revenue, amortization and interest expense associated with the issue of utility tariff bonds, sometimes referred to as rate reduction bonds or securitization bonds. EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations. *Continued on next page.*
Source: Fitch Ratings, company reports.

Utility Distribution Companies (Continued)

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
BBB– IDR												
Central Illinois Public Service Company	1.4	3.6	4.4	5.0	18.9	5.3	51.1	3.6	45.3	104.2	4.3	2.5
Illinois Power Company[a]	1.0	1.5	2.2	9.5	7.9	12.6	53.2	1.3	45.4	34.4	6.2	0.2
Metropolitan Edison Company	4.0	8.1	5.0	2.3	21.2	4.7	44.6	—	55.4	117.2	10.5	8.6
Michigan Consolidated Gas Company	2.3	3.9	3.1	5.6	9.5	10.5	61.5	—	38.5	(26.4)	7.1	9.6
Ohio Edison Company	3.1	5.4	4.1	2.6	22.0	4.5	58.0	—	42.0	15.8	14.8	14.8
Oncor Electric Delivery Company[a]	3.0	4.4	3.7	3.9	15.8	6.3	40.7	—	59.3	45.2	32.9	(6.8)
Pennsylvania Electric Company	3.4	5.5	5.4	3.2	25.0	4.0	52.7	—	47.3	56.3	13.5	8.7
Rochester Gas & Electric Corp.	2.6	3.8	3.3	4.2	14.2	7.0	63.7	—	36.3	43.7	13.5	0.7
BBB– Median	**2.8**	**4.2**	**3.9**	**4.1**	**17.3**	**5.8**	**53.0**	**—**	**45.4**	**44.5**	**12.0**	**5.6**
BB+ IDR												
Cleveland Electric Illuminating Company	4.1	6.0	4.2	2.6	20.8	4.8	55.1	—	44.9	219.7	28.4	18.4
Commonwealth Edison Company	1.9	3.3	4.3	4.3	23.6	4.2	41.2	1.3	57.4	113.2	10.9	3.0
Texas-New Mexico Power Company	2.8	5.0	3.1	3.7	11.4	8.7	43.9	—	56.1	80.4	26.8	(2.1)
Toledo Edison Company	2.1	4.6	3.4	3.0	17.2	5.8	61.7	—	38.3	(145.0)	12.6	15.5
BB+ Median	**2.4**	**4.8**	**3.8**	**3.4**	**19.0**	**5.3**	**49.5**	**—**	**50.5**	**96.8**	**19.7**	**9.3**

[a]Excludes debt, revenue, amortization and interest expense associated with the issue of utility tariff bonds, sometimes referred to as rate reduction bonds or securitization bonds. EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations.
Source: Fitch Ratings, company reports.

Midstream Companies

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
BBB+ IDR												
DCP Midstream, LLC	8.0	9.7	9.0	1.8	45.6	2.2	65.4	—	29.1	(11.7)	10.2	79.2
BBB+ Median	8.0	9.7	9.0	1.8	45.6	2.2	65.4	—	29.1	(11.7)	10.2	79.2
BBB IDR												
CenterPoint Energy Resources Corp.	3.4	4.4	3.8	4.1	15.3	6.6	53.6	—	46.4	48.9	7.6	10.6
Northwest Pipeline Corporation	4.3	6.1	6.2	2.4	35.5	2.8	36.9	—	63.1	(227.8)	46.0	13.1
Panhandle Eastern Pipe Line Company	3.5	4.7	4.4	4.7	15.8	6.3	59.7	—	40.3	63.1	42.9	12.1
Spectra Energy Capital, LLC[a]	2.2	3.0	4.0	5.0	19.6	5.1	61.7	—	34.0	80.4	28.3	18.2
Transcontinental Gas Pipe Line Corp.	4.0	6.4	5.5	2.0	34.2	2.9	26.9	—	73.1	52.9	32.7	42.1
BBB Median	3.5	4.7	4.4	4.1	19.6	5.1	53.6	—	46.4	52.9	32.7	13.1
BBB- IDR												
Colorado Interstate Gas Company	4.0	4.9	5.6	3.1	29.8	3.4	42.6	—	57.4	38.1	47.4	16.3
El Paso Natural Gas Company	3.0	3.9	4.5	3.3	27.4	3.7	39.3	—	60.7	29.6	45.9	7.4
Southern Natural Gas Company	3.6	4.3	4.7	2.8	30.7	3.3	36.6	—	63.4	61.6	50.2	15.1
Southern Union Company	2.5	3.4	3.4	4.2	16.9	5.9	53.7	9.3	37.0	67.7	18.7	13.2
Tennessee Gas Pipeline Company	2.1	3.4	3.5	3.4	21.9	4.6	34.3	—	65.7	125.4	31.6	3.5
Williams Companies, Inc.	3.9	5.9	6.2	2.0	43.3	2.3	46.3	0.2	49.8	89.4	20.6	19.1
BBB- Median	3.3	4.1	4.6	3.2	28.6	3.5	40.9	—	59.1	64.7	38.8	14.1
BB+ IDR												
El Paso Corporation	2.5	3.8	3.4	3.9	16.4	6.1	76.2	3.0	17.8	80.3	45.5	(22.0)
Knight Inc.	2.5	3.9	3.3	5.0	11.8	8.5	59.5	—	21.1	54.9	12.9	(58.9)
BB+ Median	2.5	3.9	3.4	4.4	14.1	7.3	67.8	1.5	19.4	67.6	29.2	(40.4)

[a]Ratios reflect consolidated parent company financials. EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations.
Source: Fitch Ratings, company reports.

Competitive Generating Companies

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	DEBT/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
BBB+ IDR												
Ameren Energy Generating Company	4.9	6.1	6.5	2.8	32.0	3.1	57.5	—	42.5	45.1	29.7	26.1
Exelon Generation Company, LLC	21.2	22.7	23.7	0.6	154.2	0.6	29.7	—	70.3	146.2	37.1	41.7
PSEG Power LLC	10.2	11.1	8.5	1.3	50.2	2.0	42.8	—	57.2	117.9	25.7	29.8
Southern Power Company	3.4	4.4	4.2	3.3	22.4	4.5	53.3	—	46.7	340.0	23.3	13.0
BBB+ Median	7.6	8.6	7.5	2.1	41.1	2.6	48.0	—	52.0	132.0	27.7	27.9
BBB IDR												
PPL Energy Supply LLC	4.4	5.4	4.3	3.4	18.1	5.5	54.6	—	45.3	25.3	21.3	15.4
BBB Median	4.4	5.4	4.3	3.4	18.1	5.5	54.6	—	45.3	25.3	21.3	15.4
BBB– IDR												
Allegheny Energy Supply Company, LLC	4.6	5.3	5.8	2.7	33.9	2.9	59.7	—	37.7	110.1	33.9	30.7
Brookfield Renewable Power Inc.	2.0	2.6	2.7	7.1	9.4	10.7	78.0	—	18.7	361.5	53.9	35.8
System Energy Resources Inc.	3.3	5.5	6.1	2.9	32.4	3.1	51.2	—	48.8	112.0	35.7	10.6
BBB– Median	3.3	5.3	5.8	2.9	32.4	3.1	59.7	—	37.7	112.0	35.7	30.7
BB+ IDR												
PSEG Energy Holdings L.L.C.	2.3	2.6	(0.6)	3.8	(16.3)	(6.1)	42.7	—	56.8	(3,875.0)	22.4	(15.7)
BB+ Median	2.3	2.6	(0.6)	3.8	(16.3)	(6.1)	42.7	—	56.8	(3,875.0)	22.4	(15.7)
BB IDR												
Midwest Generation LLC	9.0	10.9	9.8	1.7	49.1	2.0	26.9	—	73.1	292.2	39.0	13.5
BB Median	9.0	10.9	9.8	1.7	49.1	2.0	26.9	—	73.1	292.2	39.0	13.5
BB– IDR												
Edison Mission Energy	1.8	2.2	2.7	6.4	12.7	7.9	71.0	—	28.1	132.1	30.8	21.8
BB– Median	1.8	2.2	2.7	6.4	12.7	7.9	71.0	—	28.1	132.1	30.8	21.8
B+ IDR												
AES Corporation	1.7	2.1	2.1	4.2	12.5	8.0	71.9	—	14.6	76.2	20.8	36.1
Mirant Corporation	5.5	6.1	3.5	1.9	21.9	4.6	41.6	—	58.4	99.5	40.8	27.9
B+ Median	3.6	4.1	2.8	3.0	17.2	6.3	56.7	—	36.5	87.8	30.8	32.0
B IDR												
Dynegy Holdings Inc.	1.5	2.3	1.8	5.9	6.0	16.7	57.2	—	43.0	52.2	19.0	4.5
Dynegy Inc.	1.5	2.3	1.8	5.9	6.0	16.6	57.8	—	42.5	52.2	19.0	3.9
NRG Energy, Inc.	3.4	4.4	2.9	2.9	14.6	6.8	54.4	5.3	40.3	147.8	33.0	20.9
RRI Energy, Inc.	1.0	2.3	2.5	4.8	13.6	7.4	43.3	—	56.7	58.7	2.1	(17.9)
B Median	1.5	2.3	2.2	5.3	9.8	12.0	55.8	—	42.8	55.5	19.0	4.2

EBIT – Earnings before interest and taxes. EBITDA – Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations.
Source: Fitch Ratings, company reports.

Global Power Utilities with Utility Tariff Bonds — Unadjusted Credit Measures

(As of Dec. 31, 2008)

	Interest Coverage (x)			Leverage			Capital Structure (%)			Liquidity	Profitability (%)	
Company Name	Operating EBIT/ Interest Expense	Operating EBITDA/ Interest Expense	FFO/Interest Expense	Debt/Operating EBITDA (x)	FFO/ Debt (%)	Debt/ FFO (x)	Total Debt/ Total Capital	Total Hybrid Equity/ Total Capital	Common Equity/ Total Capital	% Internal Generation	Operating Margin	ROE
AEP Texas Central Company	1.5	2.8	1.6	6.0	9.6	10.4	84.8	0.1	15.0	(8.6)	24.7	17.7
Allegheny Energy, Inc.	3.5	4.7	3.4	3.9	18.5	5.4	59.8	—	40.2	66.5	23.9	14.7
Ameren Corporation	3.1	4.7	3.8	4.0	20.4	4.9	53.2	1.0	45.8	49.2	17.4	8.8
American Electric Power Co., Inc.	2.7	4.3	2.9	4.5	15.2	6.6	63.0	0.2	36.8	47.1	18.1	13.3
Atlantic City Electric Company	2.5	4.1	2.2	4.1	13.0	7.7	66.3	0.3	33.4	46.3	9.4	12.6
Baltimore Gas and Electric Company	1.3	3.0	2.7	6.4	14.4	6.9	58.4	7.4	34.2	(3.5)	5.1	2.4
CMS Energy Corporation	2.0	3.5	2.3	4.9	13.1	7.6	71.2	2.3	26.5	54.5	11.5	12.6
CenterPoint Energy Houston Electric LLC	2.2	4.1	2.7	4.6	14.2	7.0	73.6	—	26.4	(29.0)	28.4	12.0
CenterPoint Energy, Inc.	2.1	3.3	2.6	5.4	14.8	6.8	84.0	—	16.0	43.7	11.2	23.2
Connecticut Light & Power Company	2.6	5.8	3.4	3.5	16.8	6.0	57.0	1.7	41.3	18.1	10.5	9.6
Constellation Energy, Inc.	2.7	4.4	1.0	5.6	4.1	24.4	68.8	5.4	25.8	(85.5)	4.8	(31.2)
Consumers Energy Company	3.1	5.4	5.1	3.4	28.1	3.6	54.7	0.4	44.9	68.7	11.9	9.9
DTE Energy Company	2.2	4.0	3.6	4.4	20.5	4.9	58.6	1.4	40.0	78.4	12.0	9.2
Detroit Edison Company	2.7	5.3	4.0	3.4	22.0	4.5	59.8	—	40.2	88.5	16.4	9.7
Energy Future Holdings Corporation	0.7	1.2	0.3	10.8	2.4	41.4	105.4	—	(5.4)	49.7	20.6	(624.0)
Entergy Corporation	3.6	5.3	5.3	3.7	27.0	3.7	58.5	3.5	38.0	122.3	17.4	15.4
Entergy Texas, Inc.	1.7	2.7	(1.6)	6.4	(9.4)	(10.6)	59.9	—	40.1	(10.7)	6.8	6.1
Exelon Corporation	6.4	8.3	6.6	1.9	42.0	2.4	53.6	1.5	45.0	135.4	28.1	25.8
FPL Group, Inc.	3.5	5.2	4.1	4.1	19.6	5.1	55.5	6.5	38.0	116.6	17.2	14.6
FirstEnergy Corp.	4.2	6.7	3.7	3.0	18.4	5.4	62.8	—	37.2	51.0	21.6	15.6
Florida Power & Light Company	4.6	7.0	5.6	2.7	29.4	3.4	44.0	—	56.0	93.7	13.1	10.3
Illinois Power Company	1.0	2.1	1.7	6.8	11.9	8.4	53.0	1.3	45.6	34.4	6.1	0.2
Jersey Central Power & Light Co.	4.4	9.1	4.8	1.9	27.9	3.6	38.1	—	61.9	95.4	12.5	6.5
NSTAR	3.5	6.0	4.6	3.3	23.3	4.3	62.4	0.7	36.9	57.1	15.9	13.6
NSTAR Electric	4.9	8.5	6.4	2.7	28.1	3.6	51.2	0.8	48.1	71.0	17.1	11.7
NorthWestern Corporation	2.7	4.0	3.2	3.5	23.0	4.3	54.1	—	45.9	116.8	13.5	8.6
Northeast Utilities	2.2	4.7	2.9	4.3	14.1	7.1	64.3	0.1	35.6	22.9	10.2	8.8
Oncor Electric Delivery Company	2.7	4.3	2.7	4.1	15.1	6.6	44.9	—	55.1	45.2	32.8	(6.8)
PECO Energy Company	3.1	6.9	4.9	2.2	32.6	3.1	58.6	3.5	37.9	(31.6)	12.6	15.3
Pepco Holdings, Inc.	2.3	3.5	3.3	5.2	18.5	5.4	58.6	0.0	41.4	20.4	7.2	7.3
PPL Corporation	4.0	5.6	3.5	3.3	19.0	5.3	61.5	1.6	36.8	55.7	22.6	17.5
PPL Electric Utilities Corporation	3.4	7.2	5.7	2.3	34.1	2.9	54.3	6.6	39.2	89.2	11.0	12.0
Pacific Gas & Electric Company	3.2	5.6	5.1	2.9	30.7	3.3	54.2	0.9	44.9	49.8	15.5	12.9
Public Service Company of New Hampshire	2.5	4.7	3.1	4.1	16.0	6.2	60.4	—	39.6	34.3	10.8	9.9
Public Service Electric & Gas Company	2.8	4.6	2.8	3.4	18.1	5.5	57.8	0.7	41.5	95.9	10.1	10.4
Public Service Enterprise Group Incorporated	4.4	5.7	3.8	2.7	25.1	4.0	53.6	0.4	46.0	86.0	19.6	15.8
Western Massachusetts Electric Company	2.4	4.0	2.8	5.5	12.6	8.0	64.8	—	35.2	17.9	10.6	7.5

EBIT – Earnings before interest and taxes. EBITDA Earnings before interest, taxes, depreciation and amortization. FFO – Funds from operations.
Source: Fitch Ratings, company reports.

Hybrid Debt and Equity Adjustments

(As of Dec. 31, 2008)

Company Name	Security Type	Amount Outstanding ($ Mil.)	% Equity Credit
AEP Texas Central Company	Cumulative Preferred Stock	6	75
AEP Texas North Company	Cumulative Preferred Stock	2	75
Alabama Power Company	Cumulative Preferred Stock	342	75
Alabama Power Company	Preference stock	343	100
Ameren Corporation	Cumulative Preferred Stock	195	75
Appalachian Power Company	Cumulative Preferred Stock	18	75
Atlantic City Electric Company	Cumulative Preferred Stock	6	75
Avista Corp.	Junior Subordinated Notes	113	75
Baltimore Gas and Electric Company	Cumulative Preferred Stock	40	75
Baltimore Gas and Electric Company	Preferred Stock	150	75
Baltimore Gas and Electric Company	Trust Preferred Securities	258	75
Carolina Power & Light Company	Cumulative Preferred Stock	59	75
Central Hudson Gas & Electric Corp	Cumulative Preferred Stock	21	75
Central Illinois Light Company	Cumulative Preferred Stock	19	75
Central Illinois Public Service Company	Cumulative Preferred Stock	50	75
Central Maine Power Company	Cumulative Preferred Stock	14	75
CILCORP Inc.	Cumulative Preferred Stock	19	75
CMS Energy Corporation	Cumulative Preferred Stock	294	75
ComEd Financing III	Trust Preferred Securities	206	75
Connecticut Light and Power Co.	Cumulative Preferred Stock	116	75
Connecticut Natural Gas	Cumulative Preferred Stock	1	75
Consolidated Edison Co. of NY	Cumulative Preferred Stock	213	75
Consolidated Edison, Inc.	Cumulative Preferred Stock	213	75
Constellation Energy, Inc.	Preference Stock	190	75
Constellation Energy, Inc.	Trust Preferred Securities	258	75
Constellation Energy, Inc.	Junior Subordinated Debentures	450	75
Constellation Energy, Inc.	Mandatorily Redeemable Preferred Stock	1,000	0
Consumers Energy Company	Cumulative Preferred Stock	44	75
Dayton Power and Light	Cumulative Preferred Stock	23	75
Dominion Resources	Enhanced Junior Subordinated Notes	800	75
Dominion Resources	Trust Preferred Securities	268	75
Dominion Resources	Cumulative Preferred Stock	257	75
DPL, Inc.	Cumulative Preferred Stock	23	75
DTE Energy Company	Trust Preferred Securities	289	75
Edison International	Preference Stock	787	100
Edison International	Cumulative Preferred Stock	120	75
El Paso Corporation	Cumulative Preferred Stock	750	75
Empire District Electric Company	Trust Preferred Securities	50	75
Energy East	Cumulative Preferred Stock	25	75
Entergy Arkansas, Inc.	Cumulative Preferred Stock	116	75
Entergy Corp.	Cumulative Preferred Stock	311	75
Entergy Corp.	Equity-linked Notes	500	100
Entergy Gulf States, Inc.	Cumulative Preferred Stock	10	75
Entergy Louisiana, LLC.	Cumulative Preferred Stock	100	75
Entergy Mississippi, Inc.	Cumulative Preferred Stock	50	75
Entergy New Orleans, Inc.	Cumulative Preferred Stock	20	75
Enterprise Products Operating, L.P.	Junior Subordinated Notes	1,233	75
Exelon Corp.	Cumulative Preferred Stock	87	75%
Exelon Corp.	Trust Preferred Securities	390	75%
Florida Power Corporation	Cumulative Preferred Stock	34	75%
FPL Group Capital	Junior Subordinated Debentures	2,384	75%
Georgia Power Company	Non-Cumulative Preference Stock	221	100%
Georgia Power Company	Non-Cumulative Preferred Stock	45	100%
Gulf Power Company	Preference Stock	98	75%
Illinois Power Company	Cumulative Preferred Stock	46	75%
Indiana Michigan Power Company	Cumulative Preferred Stock	8	75%
Indianapolis Power & Light Company	Cumulative Preferred Stock	60	75%
MDU Resources Group, Inc.	Cumulative Preferred Stock	15	75
MidAmerican Energy Company	Cumulative Preferred Stock	30	75
MidAmerican Energy Holdings Company	Cumulative Preferred Stock	128	75
Mirant Americas Generation, LLC	Preferred Stock	345	100
Mirant Mid-Atlantic, LLC	Preferred Stock	211	100
Mirant North America, LLC	Preferred Stock	211	100
Mississippi Power Company	Cumulative Preferred Stock	33	75
New York State Electric & Gas Corp	Cumulative Preferred Stock	10	75
Northeast Utilities	Cumulative Preferred Stock	116	75
Northern Illinois Gas Company	Cumulative Preferred Stock	5	75
NRG Energy, Inc.	Cumulative Preferred Stock	1,100	75
NSTAR	Cumulative Preferred Stock	43	75
NSTAR Electric Co.	Cumulative Preferred Stock	43	75
Ohio Power Company	Cumulative Preferred Stock	17	75
Pacific Enterprises	Cumulative Preferred Stock	80	75
Pacific Gas and Electric	Cumulative Preferred Stock	258	75
PacifiCorp	Cumulative Preferred Stock	41	75
PECO Energy Co.	Cumulative Preferred Stock	87	75
PECO Trust III & PECO Trust IV	Trust Preferred Securities	184	75
PEPCO Holdings	Cumulative Preferred Stock	6	75
PNM Resources Inc.	Cumulative Preferred Stock	112	75
PPL Capital Funding, Inc.	Junior Subordinated Notes	500	75
PPL Electric Utilities Corp.	Cumulative Preferred Stock	51	75
PPL Electric Utilities Corp.	Preference Stock	250	100
Progress Energy Inc.	Cumulative Preferred Stock	93	75
PSE&G	Cumulative Preferred Stock	80	75
Public Service Company of New Mexico	Cumulative Preferred Stock	12	75
Public Service Company of Oklahoma	Cumulative Preferred Stock	5	75
Public Service Enterprise Group Inc.	Cumulative Preferred Stock	80	75

Note: Equity credit based on Fitch criteria. *Continued on next page.*
Source: Fitch Ratings, company reports.

Hybrid Debt and Equity Adjustments (Continued)

(As of Dec. 31, 2008)

Company Name	Security Type	Amount Outstanding ($ Mil.)	% Equity Credit
San Diego Gas & Electric Company	Cumulative Preferred Stock	79	75
SCANA Corporation	Cumulative Preferred Stock	106	75
SCANA Corporation	Preferred Stock	7	100
Sempra Energy	Cumulative Preferred Stock	79	75
South Carolina Electric & Gas Co.	Cumulative Preferred Stock	106	75
South Carolina Electric & Gas Co.	Preferred Stock	7	100
Southern California Edison	Cumulative Preferred Stock	120	75
Southern California Edison	Preference Stock	800	100
Southern California Gas Company	Cumulative Preferred Stock	22	75
Southern Company	Cumulative Preferred Stock	375	75
Southern Company	Preferred Stock	45	100
Southern Company	Preference Stock	662	100
Southern Union Company	Junior Subordinated Notes	600	75
Southern Union Company	Preferred Stock	115	100
Southwestern Electric Power Company	Cumulative Preferred Stock	5	75
Teppco Partners, L.P.	Junior Subordinated Notes	300	75
Union Electric Company	Cumulative Preferred Stock	113	75
Virginia Electric Power Co.	Cumulative Preferred Stock	257	75
Washington Gas Light Company	Cumulative Preferred Stock	28	75
Westar Energy, Inc.	Cumulative Preferred Stock	21	75
WGL Holdings, Inc.	Cumulative Preferred Stock	28	75
Williams Companies Inc.	Junior Subordinated Debentures	53	75
Wisconsin Electric Power Company	Cumulative Preferred Stock	30	75
Wisconsin Energy Corporation	Cumulative Preferred Stock	30	75
Xcel Energy Inc.	Cumulative Preferred Stock	105	75
Xcel Energy Inc.	Junior Subordinated Notes	400	75

Note: Equity credit based on Fitch criteria.
Source: Fitch Ratings, company reports.

Corporate Ratio Definitions

Earnings Before Interest and Taxes (EBIT) Interest Coverage

Numerator: Operating income before nonrecurring items plus above-the-line state and federal income taxes, if applicable.

Denominator: Gross interest expense including distributions on hybrid securities, before credit for capitalized interest and/or debt component of allowance for funds used during construction (AFUDC). For parent companies, subsidiary preferred dividends are also added to interest expense.

Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) Interest Coverage

Numerator: Operating income before nonrecurring items plus above-the-line state and federal income taxes, if applicable, plus depreciation and amortization.

Denominator: Gross interest expense including distributions on hybrid securities, before credit for capitalized interest and/or debt component of AFUDC. For parent companies, subsidiary preferred dividends are also added to interest expense.

Funds From Operations (FFO) Interest Coverage

Numerator: Net cash flow from operations, as reported, before changes in working capital plus gross interest expense including distributions on hybrid securities, before credit for capitalized interest and/or debt component of AFUDC.

Denominator: Gross interest expense including distributions on hybrid securities, before credit for capitalized interest and/or debt component of AFUDC. For parent companies, subsidiary preferred dividends are added to interest expense.

Debt/EBITDA

Numerator: Total long- and short-term debt, including capitalized lease obligations and the debt component of hybrid securities, plus off-balance-sheet debt or debt equivalents, less utility tariff bond debt plus current portion of long-term debt and capitalized lease obligations.

Denominator: Operating income before nonrecurring items plus above-the-line state and federal income taxes, if applicable, plus depreciation and amortization.

FFO/Debt

Numerator: Net cash flow from operations, as reported, before changes in working capital.

Denominator: Total long- and short-term debt, including capitalized lease obligations and the debt component of hybrid securities, plus off-balance-sheet debt or debt equivalents, less utility tariff bond debt, plus current portion of long-term debt and capitalized lease obligations.

Debt/FFO

Numerator: Total long- and short-term debt, including capitalized lease obligations and the debt component of hybrid securities, plus off-balance-sheet debt or debt equivalents, less utility tariff bond debt, plus current portion of long-term debt and capitalized lease obligations.

Denominator: Net cash flow from operations, as reported, before changes in working capital.

Debt as % of Total Capitalization

Numerator: Total long- and short-term debt, including capitalized lease obligations and the debt component of hybrid securities, plus off-balance-sheet debt or debt equivalents, less utility tariff bond debt plus current portion of long-term debt and capitalized lease obligations.

Denominator: Total long- and short-term debt, including capitalized lease obligations and the debt component of hybrid securities, plus off-balance-sheet debt or debt equivalents plus the equity portion of hybrid securities plus common equity.

Hybrid Equity as % of Total Capitalization

Numerator: Equity portion of hybrid securities.

Denominator: Total long- and short-term debt, including capitalized lease obligations and the debt component of hybrid securities, plus off-balance-sheet debt or debt equivalents plus equity portion of hybrid securities, plus common equity.

Corporate Ratio Definitions (Continued)

Common Equity as % Total Capitalization

Numerator: Total common equity.

Denominator: Total long- and short-term debt, including capitalized lease obligations and the debt component of hybrid securities, plus off-balance-sheet debt or debt equivalents, plus equity component of hybrid securities plus common equity.

% Internal Cash Generation

Numerator: Cash from operations, as reported, before changes in working capital, minus preferred/preference and common dividends.

Denominator: Gross capital expenditures plus investments in nuclear decommissioning funds.

Operating Margin

Numerator: Operating income before nonrecurring items plus above-the-line state and federal income taxes, if applicable.

Denominator: Total operating revenue.

Return on Average Common Equity

Numerator: Earnings available for common shareholders.

Denominator: Beginning-of-year common equity plus end-of-year common equity divided by two.

Note: The above ratios are adjusted to exclude the effect of issuing utility tariff bonds, sometimes referred to as rate-reduction bonds or transition bonds. The adjustments affect the calculations of EBIT, EBITDA, interest expense, debt, FFO and internal cash generation. The income statement adjustments have the effect of reducing EBITDA by the amount of payments to the utility tariff bond trust, which is roughly equivalent to the interest and principal payments on the utility tariff bonds, and EBIT and interest expense by the amount of the interest payments on the bonds. The full amount of the utility tariff bonds are also excluded from debt in calculating leverage ratios, and FFO is reduced by the debt amortization.

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Request For Comments: Imputing Debt To Purchased Power Obligations

Publication date: 01-Nov-2006

Primary Credit Analysts: David Bodek, New York (1) 212-438-7969; david_bodek@standardandpoors.com
Richard W Cortright, Jr., New York (1) 212-438-7665; richard_cortright@standardandpoors.com
Solomon B Samson, New York (1) 212-438-7653; sol_samson@standardandpoors.com

Secondary Credit Analysts: Arthur F Simonson, New York (1) 212-438-2094; arthur_simonson@standardandpoors.com
Scott Taylor, New York (1) 212-438-2057; scott_taylor@standardandpoors.com
Arleen Spangler, New York (1) 212-438-2098; arleen_spangler@standardandpoors.com

Standard & Poor's Ratings Services is requesting comments from market participants about one specific element of its refined methodology for imputing debt to purchased power obligations involving utility companies.

Proposal Summary

Standard & Poor's is abandoning its practice of not imputing debt for purchased power agreements (PPA) with terms of three years or less. In addition, where there is a high probability that the utility will have an ongoing obligation to serve load beyond the nominal tenor of short-term contracts, which is almost always the case, Standard & Poor's is contemplating providing evergreen treatment to PPA obligations to reflect the long-term load serving obligations borne by utilities. Unless an electric utility faces a declining population or real prospects of customer migration to other suppliers, both of which are rare, any near-term or intermediate power supply contracts will need to be renewed or replaced with contracted or self-built capacity to continue to meet load obligations.

We acknowledge that the process of providing evergreen treatment to outstanding contracts is imprecise. Uncertainties surround the level of capacity prices that should be assumed and the duration for which contracts should be extended to reflect the load-serving obligation. Therefore, we welcome input on evergreen-related issues as we refine these aspects of the criteria.

Response Deadline

Please submit your comments on this proposal through Dec. 15, 2006, to criteriacomments@standardandpoors.com

Imputation Is Important For Credit Analysis

Standard & Poor's has for many years considered PPAs as financial obligations that electric utilities incur when they elect to purchase rather than build their own capacity, and this obligation has affected our view of utilities' creditworthiness. Standard & Poor's has historically applied a "risk factor" of 0% to 100% to the net present value (NPV) of the PPA capacity payments, and capitalized this amount. The risk factor's role is to calibrate the stringencies of debt imputation relative to our evaluation of the certainty of recovery of power purchase costs by virtue of regulatory and legislative protections. The imputation of debt and debt service is important to our credit analysis because the resulting financial adjustments affect several key credit metrics used when we assess credit quality.

The risk factor acts as a proxy for the proportion of risk borne by the utility. At 100%, all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers.

Reviewing Existing Criteria--And A Few Refinements

From time to time, Standard & Poor's has revisited the methodology employed for making the financial adjustments that incorporate the obligations created by PPAs in its credit evaluations. This article discusses the most recent refinements. It also includes a discussion of additional areas that are under consideration as potential future refinements to our ratings methodology. While we expect very modest, if any, rating changes to result from these modifications, the proposed modifications are being disseminated in this article in the interest of ensuring the ongoing transparency of our rating methodology.

Standard & Poor's published its original PPA criteria in 1991, and provided updates in 1993 and 2003. During this time, the industry has established a very strong track record of demonstrating the viability and effectiveness of the various recovery mechanisms that state regulators have established for costs associated with contracted generation capacity. Recovery mechanisms have largely performed as intended, and related write-offs have proven to be very low. These results justify the continued application of risk factors that serve to temper, often substantially, the amount of debt imputation. Ensuring meaningful comparability in the financial commitments among utilities that are building and those that are purchasing capacity to satisfy load obligations is the rationale for our imputation of debt and debt service for PPAs. PPAs essentially represent substitutes for direct, debt-financed, capital investments. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. The analytical goal of our financial adjustments for PPAs is to reflect the fixed obligation in a way that depicts any credit exposure that is added by the presence of PPAs. That said, a PPA also shifts various risks to the supplier, such as construction risk and most of the operating risk. As a result, the principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates. While it is the utility that must of course make these payments, however, to the extent that regulators and, in certain cases, legislatures, have structured recovery to assign the burden to ratepayers, the utilities' risk diminishes.

Refinements To The Methodology

With only modest liberalization of the treatment of PPAs, we are perpetuating the current ratings criteria. Current guidelines for utilities whose capacity payments are recovered in base rates provides for the application of a 50% risk factor to the NPV of the capacity payments. This approach will continue. The NPV is calculated using the utility's average cost of debt (excluding securitization debt), rather than the standardized 10% discount rate used previously. For purposes of adjusting cash flow measures, implied interest expense is calculated on the imputed debt amount. This is accomplished by applying the average cost of debt to the relevant year's imputed debt level.

To date, where PPA capacity costs were recovered through a fuel adjustment clause (FAC), as compared with base rate recovery, a risk factor of 30% has been generally used in lieu of the 50% risk factor. We view the recovery of the capacity component of a PPA through a FAC as providing greater certainty and timeliness than recovery through a base rate mechanism. (The base rate mechanism generally has greater potential for under-recovery due to variations in volume sales and fluctuations in fuel prices over time.) Based on the effectiveness of FAC mechanisms, we will adjust modestly the risk factor of 30% down to 25%.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still do not amount to pure FACs. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, a risk factor between the revised 25% FAC risk factor and the 50% risk factor will be employed in calculating adjusted ratios.

In those instances where recovery of PPA-related capacity costs is guaranteed by a legislative mechanism, the level of the risk factor will be determined by the timeliness provided by the legislative true-up mechanism. The strength of the mechanism can result in risk factors as low as 0% because legislatively prescribed recovery mechanisms are viewed as providing utilities with a greater level of protection than that provided by regulatory orders.

There are a number of utilities to which Standard & Poor's does not impute any PPA-related debt. Specifically, Standard & Poor's does not impute debt for supply arrangements if a utility acts merely as a conduit for the delivery of power (e.g., because it has been transformed into a pure transmission and distribution utility by regulators or legislation that has directed the divestiture of all generation assets). For example, in New Jersey, the vertically integrated utility companies were transformed into pure transmission and distribution utilities. The state commission, or an appointed proxy, leads an annual

auction in which suppliers bid to serve the state's retail customers, and the utilities are protected from supplier default. In New Jersey, the power supply function of the state's utilities has essentially been reduced to the delivery of power and the collection of revenues from retail customers on behalf of the suppliers. Therefore, while Standard & Poor's has continued to impute debt to New Jersey's utilities for qualifying facility and exempt wholesale generator contracts to which the utilities are parties, we do not do so for other electricity supply contracts where the utilities merely act as conduits between the winners of the regulator's supply auction and the end-user, retail customers.

Finally, Standard & Poor's is abandoning the practice of not imputing debt for contracts with terms of three years or less. In addition to abandoning our historical three-year rule, we are contemplating applying an evergreen mechanism for short-term contracts. Because expiring contracts must be replaced with either debt-financed capacity additions or replacement PPAs for regulated utilities to meet load serving obligations, Standard & Poor's must look beyond the termination of near-term and intermediate-term contracts to approximate the fixed obligations that will succeed the current contracts in evaluating a utility's financial profile.

The process of providing evergreen treatment to outstanding contracts is imprecise. Uncertainties surround the level of capacity prices that should be assumed and the duration for which contracts should be extended to reflect the load-serving obligation. Therefore, we welcome input on evergreen-related issues as we refine these aspects of the criteria over the next 45 days.

Adjusting Financial Ratios

Standard & Poor's determines the debt equivalence that it will add to a utility's balance sheet as a result of being a party to a PPA by calculating the NPV of the annual capacity payments over the life of the contract because it is the capacity payment that represents the vehicle that funds the recovery of the supplier's investment in the generation asset.

Where the PPA contract price is stated as a single, all-in energy price, Standard & Poor's will use a proxy capacity charge, stated in dollars per kilowatt-year, and multiply that figure by the number of kilowatts under contract. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine. This is a departure from the historical practice of simply halving all-in energy payments and assuming a one-to-one ratio of energy to capacity payments. This new element of the rating methodology will also be applied to generation with extremely low variable costs whose price is stated as an all-in energy price, such as nuclear and wind generation.

The discount rate used in calculating an NPV, imputed debt, and imputed interest expense is the utility's average interest rate on its outstanding debt (excluding securitization related debt). Standard & Poor's multiplies the NPV of the stream of capacity payments by the appropriate risk factor, which will generally be 25% for capacity payments that are recovered through fuel adjustment clauses and 50% for capacity payments that are recovered in base rates. This amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense by multiplying a given year's NPV of PPA-related capacity payments by the risk factor and the company's average interest rate on outstanding debt. The resulting number is added to reported interest expense to calculate adjusted interest coverage ratios.

Key ratios affected include:

- Balance sheet debt is increased by the calculated NPV of the stream of capacity payments, after the application of the risk factor, which is added to the numerator and denominator in calculating an adjusted debt-to-capitalization ratio;
- The implied interest expense derived from applying the average interest rate to the NPV figure is simultaneously treated as a reduction in power purchase expenses and added to interest expense for the calculation of the adjusted funds from operations (FFO) to interest ratio; and
- The FFO to total debt ratio is adjusted by adding the NPV of capacity payments, after the application of the risk factor, to debt in the denominator and an implied depreciation expense is added to FFO.

The depreciation expense adjustment, the last element of the principal financial adjustments cited above, represents a new element within the context of financial adjustments for PPAs (though it has been a long-standing component of the analytical adjustments for leases). Adding an implied depreciation expense to

FFO is another element that aligns the analytical treatment of PPAs with the concept of purchased power as a substitute for self-build. The depreciation expense adjustment is a vehicle for capturing the ownership-like attributes of the contracted asset and has the effect of mitigating some of the ratio impact of debt imputation.

The mechanics of these adjustments are illustrated in the table.

Adjustments To Ratios

(Mil. $)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Funds from operations	2,500					
Interest expense	650					
Directly issued debt	10,000					
Shareholders' equity	9,000					
Fixed capacity commitments	500	500	500	500	500	4,000
NPV of fixed capacity commitments						
Using a 6.5% discount rate	4,079					
Applying a 25% risk factor	1,020					
Unadjusted ratios						
FFO/interest (x)	4.9					
FFO/total debt (%)	25					
Debt/capitalization (%)	53					
Ratios adjusted for debt imputation						
FFO/interest (x)*	4.6					
FFO/total debt (%)¶	23					
Debt/capitalization (%)§	55					

*Adds implied interest to the numerator and denominator. Also adds implied depreciation to the numerator. ¶Adds implied depreciation to the numerator and adds implied debt to total debt. §Adds implied debt to both the numerator and the denominator.

Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. The NPV of the PPA will typically decrease as the maturity of the contract approaches, but on a portfolio basis, the overall NPV may remain somewhat static as old contracts roll off and new ones are executed.

Conclusion

Absent legislative assurance of recovery, or an obligation that is little more than a fiduciary role for a transmission and distribution utility, PPAs constitute a financial risk by adding fixed obligations, though history is clearly on the side of full recovery. There is ample evidence that utility regulators and commissions have intended these costs to be for the account of the ratepayer, which justifies the continued use of risk factors. The modest revisions to our methodology seek to perpetuate our use of financial adjustments that reflect the legislative and regulatory protections that mitigate regulated utilities' exposure to the fixed obligations created by PPAs.

Additional Contacts: John W Whitlock, New York (1) 212-438-7678;
john_whitlock@standardandpoors.com
Jeanny Silva, New York (1) 212-438-1776;
jeanny_silva@standardandpoors.com

STANDARD &POOR'S

RATINGSDIRECT®

June 15, 2009

Florida Power Corp. d/b/a Progress Energy Florida Inc.

Primary Credit Analyst:
Dimitri Nikas, New York (1) 212-438-7807; dimitri_nikas@standardandpoors.com

Table Of Contents

Florida Power Corp. d/b/a Progress Energy Florida Inc.

Major Rating Factors

Strengths:

- Regulatory environment is supportive of credit quality;
- Strong plant operations with above-average capacity and utilization factors; and
- Sound liquidity position including few meaningful maturities through 2010.

Corporate Credit Rating
BBB+/Stable/A-2

Weaknesses:

- Customer growth declined significantly as a result of the slowdown in the economy;
- Debt leverage is high leading to aggressive consolidated financial profile; and
- Significant capital expenditures to meet load growth and environmental requirements may pressure consolidated financial profile unless costs are recovered on a timely basis.

Rationale

The ratings Florida Power Corp. (d/b/a Progress Energy Florida Inc., PEF) reflect the consolidated credit profile of its parent, Progress Energy Inc. (Progress).

PEF is Progress' second largest subsidiary contributing about 45% of cash flow and providing electricity to 1.64 million customers in central and northwestern Florida. While the service territory has historically demonstrated attractive demographics and exhibited above-average customer growth, the recent economic slowdown has significantly reduced the number of new customers during 2008 to less than 1%. The customer base consists of residential and commercial customers that contribute 70% of sales, industrial customers at 8%, and wholesale sale customers at 15%. Total generating capacity is 9,400MW with coal/steam providing 38% of energy needs, nuclear 13%, gas 26% and purchases 21%.

The company is operating under a favorable, four-year rate agreement that started in the beginning of 2006 and ends in 2009 and which provides for an incentive-based framework, with revenue sharings going two-thirds to ratepayers and one-third to PEF if certain revenue thresholds are met. The agreement did not include a base rate increase, but base rates were adjusted by $89 million in January 2008 to account for the inclusion of the Hines Unit 4 in rate base. Standard & Poor's views the agreement, along with other past rulings, such as recovery of past under-recovered fuel and environmental costs, and the continuation of the current storm cost surcharge to fund a $130 million storm reserve as supportive of credit quality. In March 2009, the company filed for a $499 million base in March 2009. Of that amount, PEF received approval to raise rates by $70 million starting July 2009 (compared to the initial request of $76 million) to recover investment in the Bartow repowering project and an increase sufficient to earn the minimum allowed ROE of 10%. The balance of $423 million, to go into effect January 2010, if approved by the fall of 2009, reflects recovery of investment to be completed through 2009 in the company's generation and distribution system.

PEF also requested the use of calendar year 2010 as the rate case test year. As part of its fuel cost recovery effort, PEF received approval in April 2009 to reduce fuel cost deferrals by $206 million. Finally, PEF requested approval to defer recovery of $198 million of $395 million in nuclear pre-construction costs incurred through 2008, and to recover $173 million in 2009. In May 2009, the company requested recovery of $446 million of nuclear pre-construction costs reflecting the amount deferred from 2008 as well as costs incurred in 2009. As part of the filing, PEF requested recovery of the amounts over five years with $236 million to be recovered in 2010. The deferrals of the nuclear pre-construction costs reflect the need to balance cost recoveries in light of the slowdown in the Florida economy. Nevertheless, timely recovery of all costs, including fuel and capital expenditures, is important to support the company's overall credit quality.

PEF's plan to pursue the construction of two new nuclear units at the greenfield Levy site in Florida have been pushed back by at least 20 months as a result of the need to delay some pre-construction work until the company receives the combined construction and operating license. As a result, the new in-service date for the two units is now 2018-2020. The regulatory framework in Florida supports new construction with recovery of pre-construction and licensing costs, financing costs during construction, annual prudence reviews that avoid the opportunity to look back at completed investment, and the ability to recover costs for a cancelled project. Progress has selected the Westinghouse AP1000 design, with each unit having 1,100MW of generating capacity.

Consolidated capital spending is significant over the next few years to address environmental compliance, new generation, uprates at existing plants, and system growth and maintenance. Total capital spending is expected to be about $2.0 billion in 2009, $1.9 billion in 2010, and $1.65 billion in 2011, excluding nuclear fuel and new nuclear capital expenditures. Progress has an aggressive financial risk profile and for the 12 months ended March 31, 2009, credit protection measures improved modestly compared to the 2008 levels, reflecting increased depreciation and improved fuel cost recoveries. In order to support the consolidated financial profile, Progress issued about $540 million in common shares in January 2009. For the 12 months ended March 31, 2009, adjusted funds from operations (FFO) was $2.0 billion leading to adjusted FFO to interest coverage of 3.2x, adjusted FFO to total debt of 13.5%, and adjusted debt leverage of 61.0%.

Short-term credit factors

The short-term rating on PEF is 'A-2' reflecting the company's corporate credit rating as well as its stable cash-generating operations.

PEF's liquidity is viewed on a consolidated basis with that of its parent, Progress, which is adequate. As of March 31, 2009, the consolidated lines of credit totaled $2.03 billion, with $450 million available at each of the utility operating subsidiaries (fully available at PEC, $320 million available at PEF) and expiring in 2011, and $1.13 billion at the holding company expiring in 2012 with about $600 million still undrawn. Progress also had $632 million in cash and short-term investments. None of its bank facilities has rating triggers. There are no maturities in 2009, $400 million in 2010, and $1 billion in 2011.

Outlook

The stable outlook on PEF reflects the outlook of its parent, Progress. The outlook on Progress reflects the company's focus on stable, regulated electric utility operations along with an aggressive financial risk profile. Standard & Poor's expects that the large capital spending program will be funded in a balanced manner. In addition, ratings stability at the current level incorporates expectations of continued regulatory recovery of expenses

in a timely manner which will lead to a gradual improvement in credit protection metrics. However, if credit protection measures do not improve over the intermediate term such that adjusted FFO to interest coverage exceeds 3.2x, adjusted FFO to total debt exceeds 14% and debt leverage declines to 60%, the outlook may be revised to negative. In light of the company's aggressive financial risk profile and large capital spending program, a higher rating is currently not under consideration.

Accounting

Progress's financial statements are prepared under U.S. GAAP and audited by independent auditors Deloitte & Touche LLP who issued an unqualified opinion for 2008.

Standard & Poor's makes several adjustments to Progress's consolidated reported financial numbers. As of the end of 2008, Standard & Poor's adds about $930.3 million as debt equivalent corresponding to power-purchase agreements, with $57.4 million in interest expense, and $69.6 million to depreciation. The adjustment for operating-leases adds $183.9 million in debt equivalent, $11.6 million to interest expense, and $23.8 million to depreciation.

Progress has adopted SFAS No. 158 which requires companies as pension fund sponsors to recognize on their balance sheet the funded status of the plans. Standard & Poor's adds $978.3 million as off-balance-sheet debt to reflect the pension funding shortfall.

Standard & Poor's views Progress Energy's $271 million of trust-preferred securities and $93 million of preferred and preference shares as of Dec. 31, 2008, as having intermediate equity content, ascribing 50% of each amount to debt and the remaining 50% to equity for ratio computation purposes. The total amount of the hybrid security is immaterial to the company's capital structure.

In 2008, the adjustment for asset retirement obligations (AROs) totaled $248.3 million in off-balance sheet debt, with $79 million added to interest expense and $55.9 million deducted from adjusted funds from operations.

Table 1.

Progress Energy Inc. -- Peer Comparison*

Industry Sector: Energy

	Progress Energy Inc.	SCANA Corp.	Duke Energy Corp.	FPL Group Inc.	Southern Co.
Rating as of May 29, 2009	BBB+/Stable/A-2	BBB+/Stable/NR	A-/Positive/A-2	A/Stable/--	A/Stable/A-1
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	9,296.7	4,834.3	14,217.3	15,356.7	14,591.1
Net income from cont. oper.	660.0	323.3	1,630.0	1,293.7	1,549.8
Funds from operations (FFO)	1,949.3	729.2	4,149.1	3,490.9	3,352.8
Capital expenditures	2,112.9	723.8	3,878.1	1,932.2	3,231.4
Cash and short-term investments	257.3	202.3	1,518.9	481.7	239.1
Debt	12,364.8	4,320.4	17,312.7	12,068.6	17,437.0
Preferred stock	197.7	56.7	0.0	838.0	881.8
Equity	8,696.0	3,007.0	23,111.8	11,620.0	13,225.8
Debt and equity	21,060.8	7,327.4	40,424.5	23,688.6	30,662.9

Table 1.

Progress Energy Inc. -- Peer Comparison* (cont.)

Adjusted ratios					
EBIT interest coverage (x)	2.4	2.8	3.1	3.2	3.4
FFO int. cov. (X)	3.6	3.7	4.9	6.0	4.5
FFO/debt (%)	15.8	16.9	24.0	28.9	19.2
Discretionary cash flow/debt (%)	(9.6)	(6.5)	(9.0)	3.8	(7.1)
Net cash flow / capex (%)	60.9	72.3	73.9	145.0	66.2
Total debt/debt plus equity (%)	58.7	59.0	42.8	50.9	56.9
Return on common equity (%)	6.9	10.3	6.7	11.7	12.4
Common dividend payout ratio (un-adj.) (%)	94.9	64.3	78.7	50.8	78.8

*Fully adjusted (including postretirement obligations).

Table 2.

Florida Power Corp. d/b/a Progress Energy Florida Inc. -- Financial Summary*

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2008	**2007**	**2006**	**2005**	**2004**
Rating history	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB/Positive/A-2	BBB/Stable/A-2	BBB/Negative/A-3
(Mil. $)					
Revenues	4,731.0	4,749.0	4,639.0	3,955.0	3,525.0
Net income from continuing operations	385.0	317.0	328.0	260.0	335.0
Funds from operations (FFO)	557.8	788.7	1,131.9	495.0	570.7
Capital expenditures	1,569.4	1,246.0	717.0	587.4	575.6
Cash and short-term investments	19.0	23.0	23.0	218.0	12.0
Debt	5,877.2	4,317.9	2,818.7	3,119.8	2,691.8
Preferred stock	17.0	17.0	34.0	34.0	34.0
Equity	3,416.0	3,019.0	2,721.0	2,510.1	2,260.8
Debt and equity	9,293.2	7,336.9	5,539.7	5,629.8	4,952.5
Adjusted ratios					
EBIT interest coverage (x)	2.7	2.8	4.1	4.2	5.0
FFO int. cov. (x)	2.8	4.1	7.7	4.4	5.6
FFO/debt (%)	9.5	18.3	40.2	15.9	21.2
Discretionary cash flow/debt (%)	(25.5)	(8.7)	(0.9)	(4.8)	(6.9)
Net Cash Flow / Capex (%)	35.5	63.2	125.0	83.9	71.9
Debt/debt and equity (%)	63.2	58.9	50.9	55.4	54.4
Return on common equity (%)	8.1	10.7	12.2	10.2	14.8
Common dividend payout ratio (un-adj.) (%)	0	0.0	71.8	0	46.5

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of Florida Power Corp. d/b/a Progress Energy Florida Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2008--									
Florida Power Corp. d/b/a Progress Energy Florida Inc. reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	4,769.0	3,433.0	986.0	986.0	680.0	208.0	51.0	51.0	2.0	1,595.0
Standard & Poor's adjustments										
Operating leases	28.7	--	5.9	1.7	1.7	1.7	4.2	4.2	--	2.4
Intermediate hybrids reported as equity	17.0	(17.0)	--	--	--	1.0	(1.0)	(1.0)	(1.0)	--
Postretirement benefit obligations	315.3	--	(20.0)	(20.0)	(20.0)	--	17.6	17.6	--	--
Accrued interest not included in reported debt	51.0	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	28.0	(28.0)	(28.0)	--	(28.0)
Share-based compensation expense	--	--	--	7.0	--	--	--	--	--	--
Power purchase agreements	696.3	--	82.0	82.0	40.0	40.0	42.0	42.0	--	--
Asset retirement obligations	--	--	17.0	17.0	17.0	17.0	(15.0)	(15.0)	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	94.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	487.0	--	--
Total adjustments	1,108.2	(17.0)	84.9	87.7	132.7	87.7	19.8	506.8	(1.0)	(25.6)
Standard & Poor's adjusted amounts										
	Debt	**Equity**	**Operating income (before D&A)**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	5,877.2	3,416.0	1,070.9	1,073.7	812.7	295.7	70.8	557.8	1.0	1,569.4

*Florida Power Corp. d/b/a Progress Energy Florida Inc. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of June 15, 2009)*	
Florida Power Corp. d/b/a Progress Energy Florida Inc.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (5 Issues)	BBB-
Senior Secured (10 Issues)	A-
Senior Secured (1 Issue)	A/Negative
Senior Unsecured (1 Issue)	A/Developing
Senior Unsecured (2 Issues)	BBB+
Corporate Credit Ratings History	
15-Mar-2007	BBB+/Stable/A-2
25-Jul-2006	BBB/Positive/A-2
23-Nov-2005	BBB/Stable/A-2
25-Oct-2004	BBB/Negative/A-3
19-Oct-2004	BBB/Negative/A-2
Financial Risk Profile	Aggressive
Debt Maturities	
2009 $0 2010 $400 mil 2011 $1.0 bil. 2012 $950 mil. 2013 $825 mil.	
Related Entities	
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB-
Senior Secured (9 Issues)	A-
Senior Secured (11 Issues)	A/Negative
Senior Secured (3 Issues)	BBB+
Senior Unsecured (1 Issue)	BBB+
Florida Progress Corp.	
Issuer Credit Rating	BBB+/Stable/NR
Preferred Stock (1 Issue)	BBB-
Senior Unsecured (2 Issues)	BBB
Progress Energy Inc.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured (8 Issues)	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

STANDARD
&POOR'S

RATINGSDIRECT®

May 28, 2008

Florida Power Corp. d/b/a Progress Energy Florida Inc.

Primary Credit Analyst:
Dimitri Nikas, New York (1) 212-438-7807; dimitri_nikas@standardandpoors.com

Table Of Contents

Florida Power Corp. d/b/a Progress Energy Florida Inc.

Major Rating Factors

Strengths:

- Regulatory environment is supportive of credit quality;
- Attractive markets with above average customer growth; and
- Strong plant operations with above average capacity and utilization factors.

Corporate Credit Rating
BBB+/Stable/A-2

Weaknesses:

- Consolidated financial risk profile is aggressive; and
- Significant capital expenditures to meet load growth and environmental requirements may pressure consolidated financial profile unless costs are recovered on a timely basis.

Rationale

The ratings Florida Power Corp. (d/b/a Progress Energy Florida Inc., PEF) reflect the consolidated credit profile of its parent, Progress Energy Inc. (Progress).

PEF is Progress' second largest subsidiary contributing about 45% of cash flow and providing electricity to more than 1.7 million customers in central and northwestern Florida. The service territory has attractive demographics and has historically exhibited above-average customer growth. However, the recent economic slowdown has significantly reduced the number of new customers during 2008. The customer base is largely residential and commercial that contribute 71% of sales, industrial customers 8%, and wholesale sale customers 13%. Total generating capacity is 9,400MW with coal/steam providing 42% of energy needs, nuclear 13%, gas 21% and purchases 23%.

To meet future load growth needs, PEF completed the 461MW Hines Unit 4 combined cycle facility, is pursuing an uprate at its Crystal River Unit 3 nuclear plant of 180MW at a cost of $382 million to be completed by 2012, and is considering the construction of two new nuclear units a greenfield site in Levy County. PEF will file a combined construction and operating license for the new nuclear plants in 2008 with anticipated in-service date of around 2016. Standard & Poor's expects that if PEF proceeds with the project, it will do so in a manner that maintains the current credit-protection measures.

The company is operating under a favorable, four-year rate agreement that started in the beginning of 2006 and ends in 2009 and which provides for an incentive-based framework, with revenue sharings going two-thirds to ratepayers and one-third to PEF if certain revenue thresholds are met. The agreement does not include a rate increase, but base-rate revenues increased by about $52 million in 2008 with the inclusion of the Hines Unit 4 in rate base. Standard & Poor's views the agreement, along with other past rulings, such as recovery of past under-recovered fuel and environmental costs, and the continuation of the current storm cost surcharge to fund a $130 million storm reserve as supportive of credit quality. The company plans to request recovery of the costs related to the approved $382 million, 180MW uprate at the Crystal River nuclear plant through Florida's energy

bill and the FPSC's new nuclear cost recovery rule instead of through a fuel clause adjustment mechanism. The regulatory framework in Florida supports construction of new nuclear plants with recovery of pre-construction and licensing costs, financing costs during construction, annual prudence reviews that avoid the opportunity to look back at completed investment, and the ability to recover costs for a cancelled project.

Consolidated capital spending is significant over the next few years to address environmental compliance, new generation, uprates at existing plants, and system growth and maintenance. Total capital spending is expected to be about $2.4 billion for 2008, $2 billion in 2009 and $1.65 billion in 2010, excluding nuclear fuel. Progress has an aggressive financial risk profile and for the 12 months ended March 31, 2008, credit protection measures weakened modestly compared to the end of 2007, reflecting higher cash taxes and lower fuel cost recoveries. As a result, adjusted funds from operations (FFO) was $1.58 billion leading to adjusted FFO to interest coverage of 3.2x, adjusted FFO to total debt of 13.2% and adjusted debt leverage of 57.7%.

Short-term credit factors

The short-term rating on PEF is 'A-2' reflecting the company's corporate credit rating as well as its stable cash-generating operations.

PEF's liquidity is viewed on a consolidated basis with that of its parent, Progress, which is adequate. As of March 31, 2008, the consolidated lines of credit totaled $2 billion, with $450 million fully available at each of the utility operating subsidiaries and expiring in 2011, and $1.1 billion at the holding company expiring in 2012 with about $906 million still undrawn. Progress also had $400 million in cash and short-term investments. None of its bank facilities has rating triggers.

There are no material maturities at the holding company until 2011 and manageable maturities at the utility subsidiaries totaling $877 million in 2008, $400 million in 2009 and $406 million in 2011.

Outlook

The stable outlook on PEF reflects the outlook of its parent, Progress. The outlook on Progress reflects the company's focus on stable, regulated electric utility operations along with an aggressive financial risk profile. Standard & Poor's expects that the large capital spending program will be funded in a balanced manner and will lead to moderately stronger credit protection measures over the intermediate term. However, if credit protection measures do not improve over the near term such that adjusted FFO to interest coverage exceeds 3.6x and adjusted FFO to total debt exceeds 16%, the outlook will be revised to negative and ratings may be lowered. In light of the company's aggressive financial risk profile and large capital spending program, a higher rating is currently not under consideration.

Accounting

Progress's financial statements are prepared under U.S. GAAP and independently audited by Deloitte & Touche LLP, which issued an unqualified opinion for 2007.

Standard & Poor's makes several adjustments to Progress's consolidated reported financial numbers in conducting its analysis. As of the end of 2007, Standard & Poor's adds about $1.02 billion as debt equivalent corresponding to power-purchase agreements, $64.5 million in interest expense, and $68.8 million to depreciation. The company's operating-lease exposure is also material, equaling an additional $191.7 million in debt equivalent. The two adjustments increase the company's consolidated debt by 12% and interest expense by 13%.

Progress has adopted SFAS No. 158 which requires companies as pension fund sponsors to recognize on their balance sheet the funded status of the plans. The adoption of SFAS No. 158 had no material effect on the company's financial statements. Standard & Poor's adds $397.8 million as off-balance-sheet debt to reflect the pension funding shortfall.

Standard & Poor's views Progress's $271 million of trust-preferred securities and $93 million of preferred and preference shares as of Dec. 31, 2007, as having intermediate equity content, ascribing 50% of each amount to debt and the remaining 50% to equity for ratio computation purposes. However, the total amount of the hybrid security is immaterial to the company's capital structure.

In 2007, investments in decommissioning trust were higher than asset retirement obligations, resulting in no additional debt imputation for the year.

Table 1

Progress Energy Inc. -- Peer Comparison*

Industry Sector: Energy

	--Average of past three fiscal years--				
	Progress Energy Inc.	**SCANA Corp.**	**Duke Energy Corp.**	**FPL Group Inc.**	**Southern Co.**
Rating as of May 22, 2008	BBB+/Stable/A-2	A-/Negative/NR	A-/Stable/NR	A/Stable/--	A/Stable/A-1
(Mil. $)					
Revenues	9,610.3	4,653.7	15,396.9	13,829.7	13,577.6
Net income from cont. oper.	644.7	314.7	2,048.0	1,099.2	1,509.4
Funds from operations (FFO)	1,903.0	751.8	3,841.4	2,864.5	3,414.7
Capital expenditures	1,738.5	549.5	3,142.3	1,739.8	2,659.6
Cash and short-term investments	463.0	132.3	1,554.3	480.0	170.8
Debt	11,952.5	3,835.0	17,112.3	11,124.3	15,995.6
Preferred stock	213.0	56.8	0.0	503.0	1,046.8
Equity	8,486.1	2,838.1	21,515.0	10,524.1	12,340.4
Debt and equity	20,438.6	6,673.1	38,627.3	21,648.3	28,336.0
Adjusted ratios					
EBIT interest coverage (x)	2.2	2.4	3.6	2.9	3.6
FFO int. cov. (X)	3.7	4.1	4.4	5.2	5.0
FFO/debt (%)	15.9	19.6	22.4	25.8	21.3
Discretionary cash flow/debt (%)	(5.3)	(2.2)	(5.4)	0.8	(5.5)
Net cash flow / capex (%)	74.0	101.7	81.8	129.4	84.2
Total debt/debt plus equity (%)	58.5	57.5	44.3	51.4	56.4
Return on common equity (%)	7.5	11.0	9.5	11.0	13.5
Common dividend payout ratio (un-adj.) (%)	93.9	61.8	61.9	54.3	74.6

*Fully adjusted (including postretirement obligations).

Table 2

Florida Power Corp. d/b/a Progress Energy Florida Inc. -- Financial Summary*

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2007	**2006**	**2005**	**2004**	**2003**
Rating history	BBB+/Stable/A-2	BBB/Positive/A-2	BBB/Stable/A-2	BBB/Negative/A-3	BBB/Stable/A-2
(Mil. $)					
Revenues	4,749.0	4,639.0	3,955.0	3,525.0	3,152.0
Net income from continuing operations	317.0	328.0	260.0	335.0	297.0
Funds from operations (FFO)	788.5	1,131.9	495.0	570.7	434.8
Capital expenditures	1,246.0	717.0	587.4	575.6	559.0
Cash and short-term investments	23.0	23.0	218.0	12.0	10.0
Debt	4,093.5	2,818.7	3,119.8	2,691.8	2,521.2
Preferred stock	17.0	34.0	34.0	34.0	34.0
Equity	3,019.0	2,721.0	2,510.1	2,260.8	2,043.0
Debt and equity	7,112.5	5,539.7	5,629.8	4,952.5	4,564.2
Adjusted ratios					
EBIT interest coverage (x)	2.8	4.1	4.2	5.0	5.3
FFO int. cov. (x)	4.1	7.7	4.4	5.6	5.0
FFO/debt (%)	19.3	40.2	15.9	21.2	17.2
Discretionary cash flow/debt (%)	(9.1)	(0.9)	(4.8)	(6.9)	(11.6)
Net Cash Flow / Capex (%)	63.2	125.0	83.9	71.9	41.1
Debt/debt and equity (%)	57.6	50.9	55.4	54.4	55.2
Return on common equity (%)	10.7	12.2	10.2	14.8	13.2
Common dividend payout ratio (un-adj.) (%)	0.0	71.8	0.0	46.5	68.8

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of Florida Power Corp. d/b/a Progress Energy Florida Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2007--									
Florida Power Corp. d/b/a Progress Energy Florida Inc. reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	3,218.0	3,036.0	952.0	952.0	586.0	173.0	799.0	799.0	2.0	1,258.0
Standard & Poor's adjustments										
Operating leases	30.1	--	22.5	4.7	4.7	4.7	17.8	17.8	--	--
Intermediate hybrids reported as equity	17.0	(17.0)	--	--	--	1.0	(1.0)	(1.0)	(1.0)	--
Postretirement benefit obligations	48.1	--	(14.0)	(14.0)	(14.0)	--	23.4	23.4	--	--

Table 3.

Reconciliation Of Florida Power Corp. d/b/a Progress Energy Florida Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*(cont.)

Capitalized interest	--	--	--	--	--	12.0	(12.0)	(12.0)	--	(12.0)
Share-based compensation expense	--	--	--	22.0	--	--	--	--	--	--
Power purchase agreements	780.3	--	94.9	94.9	49.6	49.6	45.3	45.3	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	48.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(84.0)	--	--
Total adjustments	875.5	(17.0)	103.4	107.6	88.3	67.3	73.5	(10.5)	(1.0)	(12.0)

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	4,093.5	3,019.0	1,055.4	1,059.6	674.3	240.3	872.5	788.5	1.0	1,246.0

*Florida Power Corp. d/b/a Progress Energy Florida Inc. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that

Ratings Detail (As Of May 28, 2008)*

Florida Power Corp. d/b/a Progress Energy Florida Inc.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock	
Local Currency	BBB-
Senior Secured	
Local Currency	A-
Senior Unsecured	
Local Currency	BBB
Corporate Credit Ratings History	
15-Mar-2007	BBB+/Stable/A-2
25-Jul-2006	BBB/Positive/A-2
23-Nov-2005	BBB/Stable/A-2
25-Oct-2004	BBB/Negative/A-3
19-Oct-2004	BBB/Negative/A-2
29-Aug-2003	BBB/Stable/A-2
Financial Risk Profile	Aggressive

Ratings Detail (As Of May 28, 2008)***(cont.)**

Debt Maturities

2008 $532 mil.
2009 $0
2010 $300 mil.
2011 $300 mil.
2012 $0

Related Entities

Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.

Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock	
Local Currency	BBB-
Senior Secured	
Local Currency	A-
Senior Unsecured	
Local Currency	BBB

Florida Progress Corp.

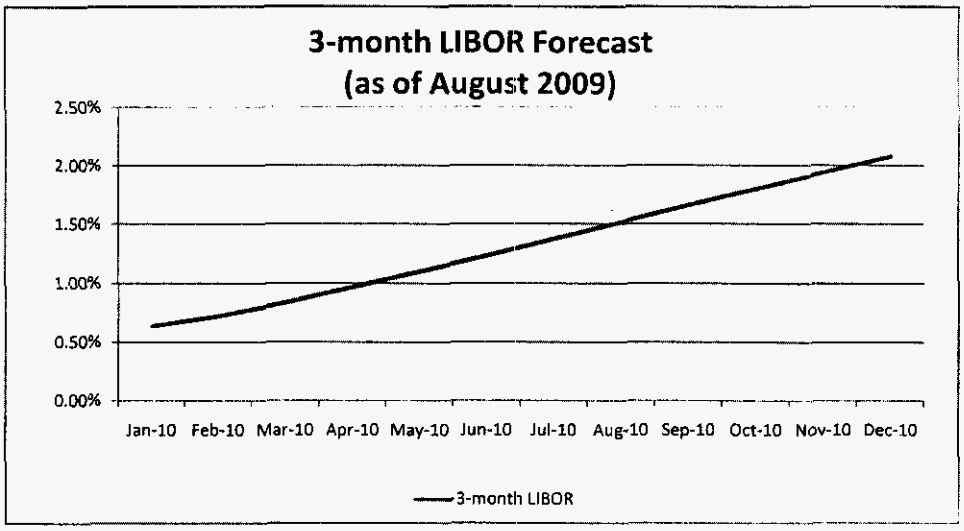
Issuer Credit Rating	BBB+/Stable/NR
Preferred Stock	
Local Currency	BBB-
Senior Unsecured	
Local Currency	BBB

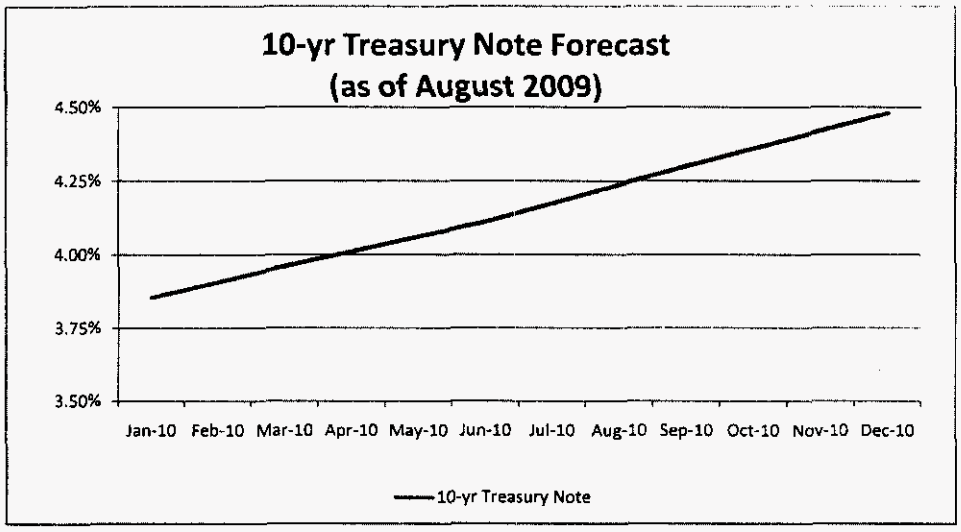
Progress Energy Inc.

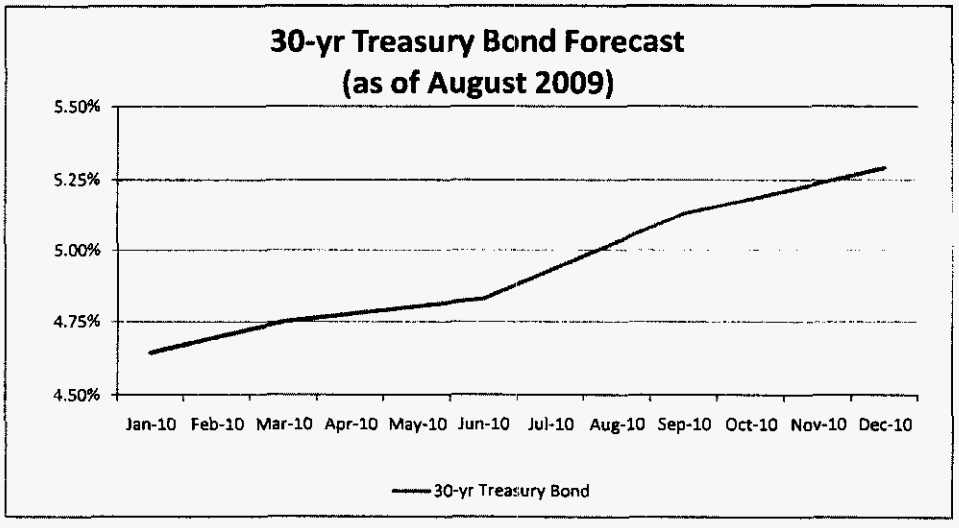
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured	
Local Currency	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Projected 2010 Interest Rate Indices
August 2009







Source: Bloomberg