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ON THE ASSESSMENT OF RISK

MARSHALL E. BLUME*

INTRODUCTION

THE CONCEPT OF RISK has so permeated the financial community that no one needs to be convinced of the necessity of including risk in investment analysis. Still of controversy is what constitutes risk and how it should be measured. This paper examines the statistical properties of one measure of risk which has had wide acceptance in the academic community: namely the coefficient of non-diversifiable risk or more simply the beta coefficient in the market model.

The next section defines this beta coefficient and presents a brief non-rigorous justification of its use as a measure of risk. After discussing the sample and its basic properties in Section III, Section IV examines the stationarity of this beta coefficient over time and proposes a method of obtaining improved assessments of this measure of risk.

II. THE RATIONALE OF BETA AS A MEASURE OF RISK

The interpretation of the beta coefficient as a measure of risk rests upon the empirical validity of the market model. This model asserts that the return from time (t-1) to t on asset i, $\tilde{R}_{it}$,[1] is a linear function of a market factor common to all assets $\tilde{M}_t$, and independent factors unique to asset i, $\tilde{\varepsilon}_{it}$.

Symbolically, this relationship takes the form

$$\tilde{R}_{it} = \alpha_i + \beta_i \tilde{M}_t + \tilde{\varepsilon}_{it}, \tag{1}$$

where the tilde indicates a random variable, α_i is a parameter whose value is such that the expected value of $\tilde{\varepsilon}_{it}$ is zero, and β_i is a parameter appropriate to asset i.[2] That the random variables $\tilde{\varepsilon}_{it}$ are assumed to be independent and

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1. In this paper, return will be measured as the ratio of the value of the investment at time t with dividends reinvested to the value of the investment at time (t-1). Dividends are assumed reinvested at time t.

2. The parameter β_i is defined as Cov $(\tilde{R}_i, \tilde{M})$/Var $(\tilde{M})$.

unique to asset i implies that Cov ($\tilde{\varepsilon}_{it}$, $\tilde{M}_t$) is zero and that Cov ($\tilde{\varepsilon}_{it}$, $\tilde{\varepsilon}_{jt}$), $i \neq j$, are zero. This last conclusion is tantamount to assuming the absence of industry effects.

The empirical validity of the market model as it applies to common stocks listed on the NYSE has been examined extensively in the literature.[3] The principal conclusions are: (1) The linearity assumption of the model is adequate.[4] (2) The variables $\tilde{\varepsilon}_{it}$ cannot be assumed independent between securities because of the existence of industry effects. However, these industry effects, as documented by King,[5] probably account for only about ten percent of the variation in returns, so that as a first approximation they can be ignored. (3) The unique factors $\tilde{\varepsilon}_{it}$ correspond more closely to non-normal stable variates than to normal ones. This conclusion means that variances and covariances of the unique factors do not exist. Nonetheless, this paper will make the more common assumption of the existence of these statistics in justifying the beta coefficient as a measure of risk since Fama[6] and Jensen[7] have shown that this coefficient can still be interpreted as a measure of risk under the assumption that the $\tilde{\varepsilon}_{it}$'s are non-normal stable variates.

That the beta coefficient, β_i, in the market model can be interpreted as a measure of risk will be justified in two different ways: the portfolio approach and the equilibrium approach.

A. *The Portfolio Approach*

The important assumption underlying the portfolio approach is that individuals evaluate the risk of a portfolio as a whole rather than the risk of each asset individually. An example will illustrate the meaning of this statement. Consider two assets, each of which by itself is extremely risky. If, however, it is always the case that when one of the assets has a high return, the other has a low return, the return on a combination of these two assets in a portfolio may be constant. Thus, the return on the portfolio may be risk free whereas each of the assets has a highly uncertain return. The discussion of such an

3. See Marshall E. Blume, "Portfolio Theory: A Step Towards Its Practical Application," forthcoming *Journal of Business;* Eugene F. Fama, "The Behavior of Stock Market Prices," *Journal of Business* (1965), 34-105; Eugene F. Fama, Lawrence Fisher, Michael Jensen, and Richard Roll, "The Adjustment of Stock Prices to New Information," *International Economic Review* (1969), 1-21; Michael Jensen, "Risk, the Pricing of Capital Assets, and the Evaluation of Investment Portfolios," *Journal of Business* (1969), 167-247; Benjamin F. King, "Market and Industry Factors in Stock Price Behavior," *Journal of Business* (1966), 139-90; and William F. Sharpe, "Mutual Fund Performance," *Journal of Business* (1966), 119-38.

4. The linearity assumption of the model should not be confused with the equilibrium requirement of William F. Sharpe, "Capital Asset Prices: A Theory of Market Equilibrium Under Conditions of Risk," *Journal of Finance* (1964), 425-42, which states that $\alpha_i = (1 - \beta_i)\ R_F$, where R_F is the risk free rate. It is quite possible that this equality does not hold and at the same time that the market model is linear.

5. King, *op. cit.*

6. Eugene F. Fama, "Risk, Return, and Equilibrium" (Report No. 6831, University of Chicago, Center for Mathematical Studies in Business and Economics, June, 1968).

7. Jensen, *op. cit.*

obvious point may seem unwarranted, but there is very little empirical work which indicates that people do in fact behave according to it.

Now if an individual is willing to judge the risk inherent in a portfolio solely in terms of the variance of the future aggregate returns, the risk of a portfolio of n securities with an equal amount invested in each, according to the market model, will be given by

$$\mathrm{Var}\,(\tilde{W}_t) = \left(\sum_{i=1}^{n} \frac{1}{n}\beta_i\right)^2 \mathrm{Var}\,(\tilde{M}_t) + \sum_{i=1}^{n} \left(\frac{1}{n}\right)^2 \mathrm{Var}\,(\tilde{\varepsilon}_{it}) \tag{2}$$

where $\tilde{W}_t$ is the return on the portfolio. Equation (2) can be rewritten as

$$\mathrm{Var}\,(\tilde{W}_t) = \bar{\beta}^2\,\mathrm{Var}\,(\tilde{M}_t) + \frac{\overline{\mathrm{Var}\,(\tilde{\varepsilon})}}{n} \tag{3}$$

where the bar indicates an average. As one diversifies by increasing the number of securities n, the last term in equation (3) will decrease. Evans and Archer[8] have shown empirically that this process of diversification proceeds quite rapidly, and with ten or more securities most of the effect of diversification has taken place. For a well diversified portfolio, Var $(\tilde{W}_t)$ will approximate $\bar{\beta}^2$ Var $(\tilde{M}_t)$. Since Var $(\tilde{M}_t)$ is the same for all securities, $\bar{\beta}$ becomes a measure of risk for a portfolio and thus β_i, as it contributes to the value of $\bar{\beta}$, is a measure of risk for a security. The larger the value of β_i, the more risk the security will contribute to a portfolio.[9]

B. *The Equilibrium Approach*

Using the market model, Sharpe[10] and Lintner,[11] as clarified by Fama,[12] have developed a theory of equilibrium in the capital markets. This theory relates the risk premium for an individual security, $E(\tilde{R}_{it}) - R_F$, where R_F is the risk free rate, to the risk premium of the market, $E(\tilde{M}_t) - R_F$, by the formula

$$E(\tilde{R}_{it}) - R_F = \beta_i[E(\tilde{M}_t) - R_F]. \tag{4}$$

The risk premium for an individual security is proportional to the risk premium for the market. The constant of proportionality β_i can therefore be interpreted as a measure of risk for individual securities.

8. John L. Evans and Stephan H. Archer, "Diversification and the Reduction of Dispersion: An Empirical Analysis," *Journal of Finance* (1968), 761-68.

9. This argument has been extended to a non-Gaussian, symmetric stable world by E. F. Fama, "Portfolio Analysis in a Stable Paretian Market," *Management Science* (1965), 404-19; and P. A. Samuelson, "Efficient Portfolio Selection for Pareto-Levy Investments," *Journal of Financial and Quantitative Analysis* (1967), 107-22.

10. Sharpe, "Capital Asset Prices," *op. cit.*

11. John Lintner, "The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets," *Review of Economics and Statistics* (1965), 13-37.

12. Eugene F. Fama, "Risk, Return, and Equilibrium: Some Clarifying Comments," *Journal of Finance* (1968), 29-40.

This theory of equilibrium, although theoretically sound, is based upon numerous assumptions which obviously do not hold in the real world. A theoretical model, however, should not be judged by the accuracy of its assumptions but rather by the accuracy of its predictions. The empirical work of Friend and Blume[13] suggests that the predictions of this model are seriously biased and that this bias is primarily attributable to the inaccuracy of one key assumption, namely that the borrowing and lending rates are equal and the same for all investors. Therefore, although Sharpe's and Lintner's theory of equilibrium can be used as a justification for β_i as measure of risk, it is a weaker and considerably less robust justification than that provided by the portfolio approach.

III. The Sample and Its Properties

The sample was taken from the updated Price Relative File of the Center for Research in Security Prices at the Graduate School of Business, University of Chicago. This file contains the monthly investment relatives, adjusted for dividends and capital changes of all common stocks listed on the New York Stock Exchange during any part of the period from January 1926 through June 1968, for the months in which they were listed. Six equal time periods beginning in July 1926 and ending in June 1968 were examined. Table 1 lists these six periods and the number of companies in each for which there was a complete history of monthly return data. This number ranged from 415 to 890.

The investment relatives for a particular security and a particular period were regressed[14] upon the corresponding combination market link relatives, which were originally prepared by Fisher[15] as a measure of the market factor. This process was repeated for each security and each period, yielding, for instance, in the July 1926 through June 1933 period, 415 separate regressions. The average coefficient of determination of these 415 regressions was 0.51. The corresponding average coefficients of determination for the next five periods were, respectively, 0.49, 0.36, 0.32, 0.25, and 0.28. These figures are consistent with King's findings[16] in that the proportion of the variance of returns explained by the market declined steadily until 1960 when his sample terminated. Since 1960, the importance of the market factor has increased slightly according to these figures.

Table 1, besides giving the number of companies analyzed, summarizes the distributions of the estimated beta coefficients in terms of the means, standard deviations, and various fractiles of these distributions. In addition, the number of estimated betas which were less than zero is given. In three of the periods,

13. Irwin Friend and Marshall Blume, "Measurement of Portfolio Performance Under Uncertainty," *American Economic Review* (1970), 561-75.

14. John Wise, "Linear Estimators for Linear Regression Systems Having Infinite Variances," (Berkeley-Stanford Mathematics-Economics Seminar, October, 1963) has given some justification for the use of least squares in estimating coefficients of regressions in which the disturbances are non-normal symmetric stable variates.

15. Lawrence Fisher, "Some New Stock-Market Indexes," *Journal of Business* (1966), 191-225.

16. King, *op. cit.*

TABLE 1

DESCRIPTIVE SUMMARY OF ESTIMATED BETA COEFFICIENTS

Period	Number of Companies	Mean	Standard Deviation	Number of BETAS less than Zero	Fractiles				
					.10	.25	.50	.75	.90
7/26-6/33	415	1.051	0.462	1	0.498	0.711	1.023	1.352	1.616
7/33-6/40	604	1.036	0.474	0	0.436	0.701	1.015	1.349	1.581
7/40-6/47	731	0.990	0.504	0	0.500	0.643	0.872	1.186	1.606
7/47-6/54	870	1.010	0.409	2	0.473	0.727	0.996	1.263	1.565
7/54-6/61	890	0.998	0.423	0	0.458	0.678	0.984	1.250	1.558
7/61-6/68	847	0.962	0.390	4	0.475	0.681	0.934	1.199	1.491

none of the estimated betas was negative. Of the 4357 betas estimated in all six periods, only seven or 0.16 per cent were negative. This means that although the inclusion of a stock which moves counter to the market can reduce the risk of a portfolio substantially, there are virtually no opportunities to do this. Nearly every stock appears to move with the market.[17]

IV. The Stationarity of Beta over Time

No economic variable including the beta coefficient is constant over time. Yet for some purposes, an individual might be willing to act *as if* the values of beta for individual securities were constant or stationary over time. For example, a person who wishes to assess the future risk of a well diversified portfolio is really interested in the behavior of averages of the β_i's over time and not directly in the values for individual securities. For the purposes of evaluating a portfolio, it may be sufficient that the historical values of β_i be unbiased estimates of the future values for an individual to act *as if* the values of the β_i's for individual securities are stationary over time. This is because the errors in the assessment of an average will tend to be less than those of the components of the average providing that the errors in the assessments of the components are independent of each other.[18] Yet, a statistician or a person who wishes to assess the risk of an individual security may have completely different standards in determining whether he would act as if the β_i's are constant over time. The remainder of the paper examines the stationarity of the β_i's from the point of view of a person who wishes to analyze a portfolio.

A. *Correlations*

To examine the empirical behavior of the risk measures for portfolios over time, arbitrary portfolios of n securities were selected as follows: The estimates of β_i were derived using data from the first period, July 1926 through June 1933, and were then ranked in ascending order.[19] The first portfolio of n securities consisted of those securities with the n smallest estimates of β_i. The second portfolio consisted of those securities with the next n smallest estimates of β_i, and so on until the number of securities remaining was less than n. The number of securities n was allowed to vary over 1, 2, 4, 7, 10, 20, 35, 50, 75, and 100. This process was repeated for each of the next four periods.

Table 2 presents the product moment and rank order correlation coefficients between the risk measures for portfolios of n securities assuming an equal investment in each security estimated in one period and the corresponding risk

17. The use of considerably less than seven years of monthly data such as two or three years to estimate the beta coefficient results in a larger proportion of negative estimates. This larger proportion is probably due to sampling errors which, as documented in Richard Roll, "The Efficient Market Model Applied to U. S. Treasury Bill Rates," (Unpublished Ph.D. thesis, Graduate School of Business, University of Chicago, 1968) may be quite large for models with non-normal symmetric stable disturbances.

18. This property of averages does not hold for all distributions (*cf.* Eugene F. Fama, "Portfolio Analysis in a Stable Paretian Market"), but for the distributions associated with stock market returns it almost certainly holds.

19. Only securities which also had complete data in the next seven year period were included in this ranking.

measure for the same portfolio estimated in the next period.[20] The risk measure calculated using the earlier data might be regarded as an individual's assessment of the future risk, and the measure calculated using the later data can be regarded as the realized risk. Thus, these correlation coefficients can be interpreted as a measure of the accuracy of one's assessments, which in this case are simple extrapolations of historical data.

TABLE 2
PRODUCT MOMENT AND RANK ORDER CORRELATION COEFFICIENTS OF BETAS FOR PORTFOLIOS OF N SECURITIES

Number of Securities per Portfolio	7/26-6/33 and 7/33-6/40		7/33-6/40 and 7/40-6/47		7/40-6/47 and 7/47-6/54		7/47-6/54 and 7/54-6/61		7/54-6/61 and 7/61-6/68	
	P.M.	Rank	P.M.	Rank	P.M.	Rank	P.M.	Rank	P.M.	Rank
1	0.63	0.69	0.62	0.73	0.59	0.65	0.65	0.67	0.60	0.62
2	0.71	0.75	0.76	0.83	0.72	0.79	0.76	0.76	0.73	0.74
4	0.80	0.84	0.85	0.90	0.81	0.89	0.84	0.84	0.84	0.85
7	0.86	0.90	0.91	0.93	0.88	0.93	0.87	0.88	0.88	0.89
10	0.89	0.93	0.94	0.95	0.90	0.95	0.92	0.93	0.92	0.93
20	0.93	0.99	0.97	0.98	0.95	0.98	0.95	0.96	0.97	0.98
35	0.96	1.00	0.98	0.99	0.95	0.99	0.97	0.98	0.97	0.97
50	0.98	1.00	0.99	0.98	0.98	0.99	0.98	0.98	0.98	0.97

The values of these correlation coefficients are striking. For the assessments based upon the data from July 1926 through June 1933 and evaluated using data from July 1933 through June 1940, the product moment correlations varied from 0.63 for single securities to 0.98 for portfolios of 50 securities. The high value of the latter coefficient indicates that substantially all of the variation in the risk among portfolios of 50 securities can be explained by assessments based upon previous data. The former correlation suggests that assessments for individual securities derived from historical data can explain roughly 36 per cent of the variation in the future estimated values, leaving about 64 per cent unexplained.[21]

These results, which are typical of the other periods, suggest that at least as measured by the correlation coefficients, naively extrapolated assessments of future risk for larger portfolios are remarkably accurate, whereas extrapolated assessments of future risk for individual securities and smaller portfolios are of some, but limited value in forecasting the future.

B. *A Closer Examination*

Table 3 presents the actual estimates of the risk parameters for portfolios of 100 securities for successive periods. For all five different sets of portfolios, the rank order correlations between the successive estimates are one, but there is obviously some tendency for the estimated values of the risk parameter to

20. Because of the small number of portfolios of 100 securities, correlations are not presented in Table 2 for these portfolios.

21. This large magnitude of unexplained variation may make the beta coefficient an inadequate measure of risk for analyzing the cost of equity for an individual firm although it may be adequate for cross-section analyses of cost of equity.

TABLE 3

ESTIMATED BETA COEFFICIENTS FOR PORTFOLIOS OF 100 SECURITIES IN TWO SUCCESSIVE PERIODS

Portfolio	7/26-6/33	7/33-6/40	7/33-6/40	7/40-6/47	7/40-6/47	7/47-6/54	7/47-6/54	7/54-6/61	7/54-6/61	7/61-6/68
1	0.528	0.610	0.394	0.573	0.442	0.593	0.385	0.553	0.393	0.620
2	0.898	1.004	0.708	0.784	0.615	0.776	0.654	0.748	0.612	0.707
3	1.225	1.296	0.925	0.902	0.746	0.887	0.832	0.971	0.810	0.861
4			1.177	1.145	0.876	1.008	0.967	1.010	0.987	0.914
5			1.403	1.354	1.037	1.124	1.093	1.095	1.138	0.995
6					1.282	1.251	1.245	1.243	1.337	1.169

change gradually over time. This tendency is most pronounced in the lowest risk portfolios, for which the estimated risk in the second period is invariably higher than that estimated in the first period. There is some tendency for the high risk portfolios to have lower estimated risk coefficients in the second period than in those estimated in the first. Therefore, the estimated values of the risk coefficients in one period are biased assessments of the future values, and furthermore the values of the risk coefficients as measured by the estimates of β_i tend to regress towards the means with this tendency stronger for the lower risk portfolios than the higher risk portfolios.

C. *A Method of Correction*

In so far as the rate of regression towards the mean is stationary over time, one can in principle correct for this tendency in forming one's assessments. An obvious method is to regress the estimated values of β_i in one period on the values estimated in a previous period and to use this estimated relationship to modify one's assessments of the future.

Table 4 presents these regressions for five successive periods of time for individual securities.[22] The slope coefficients are all less than one in agreement with the regression tendency, observed above. The coefficients themselves do change over time, so that the use of the historical rate of regression to correct

TABLE 4

MEASUREMENT OF REGRESSION TENDENCY OF ESTIMATED BETA COEFFICIENTS FOR INDIVIDUAL SECURITIES

Regression Tendency Implied Between Periods	$\beta_2 = a + b\beta_1$
7/33-6/40 and 7/26-6/33	$\beta_2 = 0.320 + 0.714\beta_1$
7/40-6/47 and 7/33-6/40	$\beta_2 = 0.265 + 0.750\beta_1$
7/47-6/54 and 7/40-6/47	$\beta_2 = 0.526 + 0.489\beta_1$
7/54-6/61 and 7/47-6/54	$\beta_2 = 0.343 + 0.677\beta_1$
7/61-6/68 and 7/54-6/61	$\beta_2 = 0.399 + 0.546\beta_1$

22. The reader should not think of these regressions as a test of the stationarity of the risk of securities over time but rather merely as a test of the accuracy of the assessments of future risk which happen to be derived as historical estimates. In this test of accuracy, the independent variable in these regressions is measured without error, so that the estimated coefficients are unbiased. In the test of the stationarity of the risk measures over time, the independent variable would be measured with error, so that the coefficients in Table 4 would be biased.

for the future rate will not perfectly adjust the assessments and may even overcorrect by introducing larger errors into the assessments than were present in the unadjusted data.

To examine the efficacy of using historical rates of regression to correct one's assessments, the estimated risk coefficients for the individual securities for the period from July 1933 through June 1940 were modified using the first equation in Table 4 to obtain adjusted risk coefficients under the assumption that the future rate of regression will be the same as the past. This process was repeated for each of the next three periods using respectively the next three equations in Table 4 to estimate the rate of regression.

Table 5 compares these adjusted assessments with the unadjusted assessments which were used in Tables 2 and 3. For the portfolios selected previously using the data from July 1933 through June 1940, both the unadjusted

TABLE 5
MEAN SQUARE ERRORS BETWEEN ASSESSMENTS AND FUTURE ESTIMATED VALUES

Number of Sec./ Port.	Assessments Based Upon 7/33-6/40 unadjusted	7/33-6/40 adjusted	7/40-6/47 unadjusted	7/40-6/47 adjusted	7/47-6/54 unadjusted	7/47-6/54 adjusted	7/54-6/61 unadjusted	7/54-6/61 adjusted
1	0.1929	0.1808	0.1747	0.1261	0.1203	0.1087	0.1305	0.1013
2	0.0915	0.0813	0.1218	0.0736	0.0729	0.0614	0.0827	0.0535
4	0.0538	0.0453	0.0958	0.0483	0.0495	0.0381	0.0587	0.0296
7	0.0323	0.0247	0.0631	0.0276	0.0387	0.0281	0.0523	0.0231
10	0.0243	0.0174	0.0535	0.0220	0.0305	0.0189	0.0430	0.0169
20	0.0160	0.0090	0.0328	0.0106	0.0258	0.0139	0.0291	0.0089
35	0.0120	0.0055	0.0266	0.0080	0.0197	0.0101	0.0302	0.0089
50	0.0096	0.0046	0.0192	0.0046	0.0122	0.0097	0.0237	0.0064
75	0.0081	0.0035	0.0269	0.0067	0.0112	0.0078	0.0193	0.0056
100	0.0084	0.0020	0.0157	0.0035	0.0114	0.0084	0.0195	0.0056

and adjusted assessments of future risk were obtained. The accuracy of these two alternative methods of assessment were compared through the mean squared errors of the assessments versus the estimated risk coefficients in the next period, July 1940 through June 1947.[23] This process was repeated for each of the next three periods.

For individual securities as well as portfolios of two or more securities, the assessments adjusted for the historical rate of regression are more accurate than the unadjusted or naive assessments. Thus, an improvement in the accuracy of one's assessments of risk can be obtained by adjusting for the historical rate of regression even though the rate of regression over time is not strictly stationary.

23. The mean square error was calculated by $\frac{\Sigma(\beta_1 - \beta_2)^2}{n}$ where β_1 is the assessed value of the future risk, β_2 is the estimated value of the risk, and n is the number of portfolios. In using an estimate of beta rather than the actual value, the mean square error will be biased upwards, but the effect of this bias will be the same for both the adjusted and unadjusted assessments.

V. Conclusion

This paper examined the empirical behavior of one measure of risk over time. There was some tendency for the estimated values of these risk measures to regress towards the mean over time. Correcting for this regression tendency resulted in considerably more accurate assessments of the future values of risk.

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Rating Methodology

Moody's Global
Infrastructure Finance

August 2009

Regulated Electric and Gas Utilities

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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

Moody's Investors Service

Regulated Electric and Gas Utilities

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

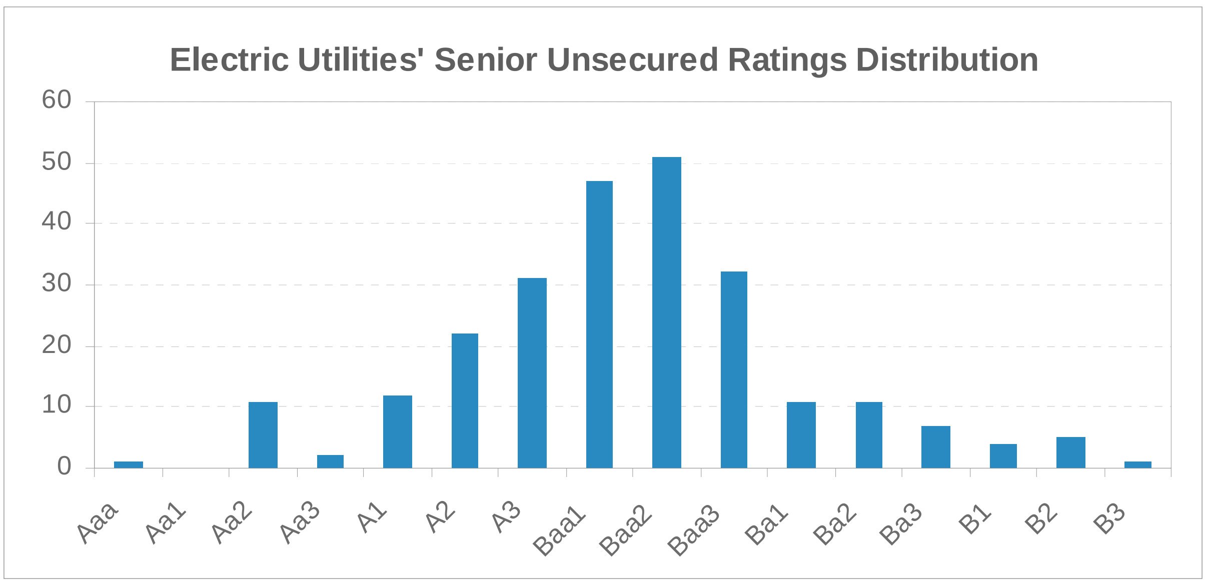
In the appendices, we also provide tables that illustrate the application of the methodology grid to 30 representative electric and gas utility companies with explanatory comments on some of the more significant differences between the grid-implied rating and our actual rating (Appendix C). We also provide 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.

Regulated Electric and Gas Utilities

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.

Regulated Electric and Gas Utilities

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.*

Regulated Electric and Gas Utilities

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.

Regulated Electric and Gas Utilities

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	

Regulated Electric and Gas Utilities

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%

Regulated Electric and Gas Utilities

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*

Regulated Electric and Gas Utilities

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%

Regulated Electric and Gas Utilities

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.

Regulated Electric and Gas Utilities

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.

Regulated Electric and Gas Utilities

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 CO_2 intensive, Eesti Energia is further exposed to the development of CO_2 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.

Regulated Electric and Gas Utilities

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

Regulated Electric and Gas Utilities

Observations and Outliers

This factor takes into account historic financial statements. Historic results help us to understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While Moody's 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.

While the vast majority of utilities' key financial metrics map fairly closely to their ratings, there are several significant outliers, which generally fall into two broad groups. The first group is composed of negative outliers and include several utilities located in stable and supportive regulatory environments and are characterized by very low business risk. In these cases, the utilities may have lower financial ratios and higher leverage than most peer companies on a global basis, but still maintain higher overall ratings. In short, the certainty provided by regulatory stability and low business risk offsets any risks that may result from lower financial ratios. Examples of such negative outliers on the financial strength factor include most of the major Japanese utilities, including Tokyo Electric Power and Kyushu Electric Power.

The second group of outliers is composed of positive outliers, whereby several financial ratios are stronger than the overall Moody's rating. These include several utilities in Latin America, such as Cemig Distribuicao, EDP-Energias do Brasil, and European Eesti Energia, which exhibit strong financial coverage ratios and low debt levels, but where ratings are constrained by a more difficult regulatory or business environment or a sovereign rating ceiling.

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.

Regulated Electric and Gas Utilities

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.

Regulated Electric and Gas Utilities

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.

Regulated Electric and Gas Utilities

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.

Regulated Electric and Gas Utilities

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Moody's Investors Service

Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers

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The methodology that Standard & Poor's Ratings Services uses to rate vertically integrated electric, gas, and combination investor-owned utilities in the U.S. is based on the same precepts that we have used for many years, though the emphasis has changed as the utility industry has evolved. The fundamental methodology encompasses two basic components—business risk and financial risk—and their relationship. Where a utility presents a strong business risk profile, the financial profile can be less robust for any given rating. Likewise, where a utility's business risk profile is weaker, its financial performance must be stronger for any given rating. For combination utilities, the gas operations may have a stabilizing influence on credit quality, but since the electric business is typically significantly larger, it is the major credit driver. *(For details on Standard & Poor's analytical approach to gas utilities, see "Key Credit Factors For Natural Gas Distributors" published Feb. 28, 2006.)*

Often, an integrated utility is a part of a larger holding company structure that also owns other businesses, frequently unregulated electricity generation. This fact does not alter how we analyze the utility, but it may affect the ultimate rating outcome due to any credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Five Factors Determine The Business Profile

Five basic characteristics define a vertically integrated utility's business profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Standard & Poor's is most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations. While considerable attention has focused in recent years on companies in states that deregulated in the late 1990s and the early part of this decade and the related credit consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management looms considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

On Standard & Poor's business profile scale (where '1' is excellent and '10' is vulnerable), vertically integrated utilities generally have satisfactory business profiles of '5' or '6'. *(See tables 1 and 2 in the Appendix below for business profile benchmarks plus a list of utilities we rate and their business profile scores.)* We view a company that owns regulated generation, transmission, and distribution operations, as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management.

Regulation

Regulation is a critical aspect that underlies integrated utilities' creditworthiness. Decisions by state public service commissions can profoundly affect financial performance. Standard & Poor's assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program and incurs substantial deferrals of fuel costs.

Standard & Poor's evaluation encompasses the administrative, judicial, and legislative processes involved in state and federal regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case-by-case with regard to the potential effect on credit quality. As frequently postulated in prior years, our evaluation of regulation focuses on the willingness and ability of regulation to provide cash flow and earnings quality adequate to meet investment needs, earnings stability through timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity. Regulators' authorization of high rates of return is of little value unless returns are realistic and achievable. Allowing high returns based on noncash items does not benefit bondholders. A regulatory jurisdiction that permits incentives whereby utilities are allowed to earn a return based on their ability to sustain rates at competitive levels is viewed favorably. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Also important is the ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses or with fixed-fuel mechanisms, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. Standard & Poor's notes that fuel-adjustment mechanisms have become more common in the industry, but not all are created equal. While some jurisdictions permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions, such as Washington State, impose a deadband in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. In Arizona, Arizona Public Service Co. has a 90/10 sharing mechanism between the company and ratepayers, respectively, for all costs passed through the power supply adjuster. The mechanism is triggered based on a date (once a year in February 2006) and not on a threshold level of deferrals. The annual adjustment is also subject to a lifetime cap of 4 mils per kilowatt-hour, which has led to power deferrals.

In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes significant cash flow drain and reduces the utility's need to issue debt during construction.

Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery. Also supportive of credit quality is the ability of the utility, commission staff, consumer advocates, and other major interveners to reach a comprehensive settlement before construction of new base load capacity. Certain states, such as Indiana, Texas, Kansas, and Minnesota, have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with environmental compliance equipment without having to file a formal rate case. Creditworthiness can also be enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing storm damage, as in Florida. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, it has shown a willingness to work with utilities to help them recover at least some of these costs on a timely basis and to start replenishing storm reserves. Finally, the greater the percentage of a utility's rates that are recovered through fixed charges rather than volume-based charges, the greater the support for credit quality.

For utilities that own a natural gas business, automatic and timely pass-through of commodity costs provides the strongest level of credit support. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels.

Due to the extreme volatility and high gas prices over the past few heating seasons, more regulators have revised gas adjustment clauses to provide monthly gas adjustments rather than awaiting the end of the heating season to begin reimbursement. This expedited treatment helps the utility to reduce any regulatory lag to recover costs and streamlines working capital needs, which in turn should allow the firm to modestly temper rising gas bills to their customers.

Both regulators and natural gas companies are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and companies are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting the company's bottom line and still allow utilities to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Key success factors include:

- Alternative ratemaking/flexibility,
- Attention to credit quality,
- Timely and consistent rate treatment,
- Support for fuel cost recovery,
- Support for a reasonable cash return on investment, and
- Support for rapid return on investment.

Markets

Assessing market dynamics begins with an economic and demographic evaluation of the service area in which a utility operates. Strength of long-term demand for energy is examined from a macroeconomic perspective, which enables Standard & Poor's to measure the affordability of rates and the staying power of demand. Distribution by classification according to total number of customers, revenues, and margins is closely scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed with some caution because the utility may be exposed to cyclical volatility and face competitive alternatives. A large residential component, on the other hand, produces a more stable and predictable revenue stream. The utility's largest customers are identified to determine their stability and importance to the bottom line because the loss of one large customer could adversely affect the utility's financial position. Moreover, large customers may turn to self-generation, potentially leading to less financial protection for the utility.

Standard & Poor's also analyzes any long-term consumption trends and the reasons behind them. Factors addressed include the market's size and growth rate, the franchise's strength, historical and projected growth rates, income levels and trends in population, employment, and per capita income. A utility with a healthy economy and customer base, as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment, will be better able to support its operations.

For the gas business, Standard & Poor's also examines customer saturation. Firms that operate in service areas with low growth potential still can expand at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to companies operating in low population growth service areas.

Despite the review of market characteristics, they are clearly a secondary consideration to regulation. In Nevada, for years the country's fastest growing state, Nevada Power Co. and Sierra Pacific Power Co. struggled to recover capital expenditures on a timely basis, and were accordingly rated as low investment-grade credits. In Florida, which has competed with Nevada for years in its pace of growth, the Florida Public Service Commission established polices of quick recovery of capital investments and, on a stand-alone basis, the state's utilities' credit metrics have remained strong.

Critical success factors include:

- A healthy and growing economy,
- Growth in population and number of customers,
- An attractive business environment, and
- An above-average residential base.

Operations

Standard & Poor's focuses on cost, reliability, safety, and quality of service when assessing a utility's operations. Management is always under pressure to optimize the use of resources, and if it is not cost-effective in meeting service standards and reliability, regulatory or competitive pressures are likely to increase. Consequently, Standard & Poor's emphasizes areas that require heightened and ongoing management attention, in the absence of which political, regulatory, or competitive problems are likely to arise.

The status of utility plant investment is reviewed with regard to generating station availability, efficiency, and utilization, as well as for compliance with existing and potential environmental and other regulatory standards. The record of plant outages, system losses, equivalent availability, load factors, heat rates, and capacity factors are examined. Important considerations include the projected capital improvements and plant additions necessary to provide high-quality, reliable service. The general condition of the assets and how well such assets are maintained are also important considerations.

Emphasis is placed on reserve margins, fuel mix, fuel contract terms, purchased-power arrangements, and system operators. Moreover, the quality and concentration of capacity is just as important as the size of reserves. Standard & Poor's recognizes that reserve requirements differ among companies, depending upon individual operating and load characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to switch generating sources to take advantage of cheaper fuels is viewed favorably. Dependence on any single fuel, or asset concentration in one or two large generating stations, can cause significant swings in a company's financial performance. Similarly, utilities that rely on nuclear generation receive an elevated degree of attention due to the scale, technical complexity, and politically sensitive nature of nuclear facilities. Indeed, the sound operation of nuclear units can define a utility's operational risk profile and its ability to achieve projected financial results. Standard & Poor's seeks to distinguish between those operators that have exhibited sound and stable operational performance, and the likelihood that it will continue, and those whose nuclear operations are vulnerable to problems that may impair financial results.

But having a large concentration of capacity based on fossil fuels also imposes certain risks. Coal-fired capacity is burdened with increased environmental costs related to reducing sulfur dioxide, nitrogen oxide, mercury, and eventually carbon dioxide emissions. Gas-fired capacity presents its own challenges, particularly the extreme volatility and significant increase in gas prices over the past few years. Buying power may be a more appropriate option for a utility than new plant construction because the utility avoids construction costs and the financial risks posed by regulatory lag when seeking recovery of costs. Purchasing power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Despite these benefits, such a strategy does commit the utility to a fixed obligation, which Standard & Poor's captures analytically through certain adjustments to financial statements. We calculate the net present value of future annual capacity payments (discounted at the company's cost of debt) over the life of the contract. Standard & Poor's then applies a risk factor against this value and adds the result to the utility's balance sheet. The risk factor is largely a function of the strength of the regulatory recovery mechanisms established to address procurement costs.

Other operational characteristics that will support an above-average evaluation for vertically integrated companies are assets that are in good physical condition and are well maintained. In addition, capital expenditures for necessary system improvements must be at manageable levels, yet sufficient to provide for constant renewal and refurbishment of the system. Operating performance, reliability statistics (such as outage duration and frequency), and efficiency measures are expected to meet industry and regional averages. Having interconnections that provide access to low-cost and diverse power supply sources is viewed favorably, as is limited environmental exposure.

For a gas company, drawing from a single interstate pipeline or relying on a particular gas basin exposes it to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects the utility from such disruptions. Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. Gas distributors benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Outdated systems requiring extensive maintenance and capital expenditures lower profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, operational efficiencies can be obtained through the use of new technology.

Critical success factors include:

- Well-maintained assets,
- Solid plant performance,
- Fuel diversity,
- Adequate generating reserves, and
- Compliance with environmental standards.

Competitiveness

For vertically integrated utilities, competitive factors include percentage of firm wholesale revenues that are most vulnerable to competition, industrial load, and revenue concentrations, particularly in energy-intensive industries; exposure of key customers to alternative suppliers; commercial concentrations; rates charged to various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Electricity competes with other fuels—particularly natural gas—for certain segments of the market like space heating, water heating, and cooking. Thus, high electricity prices, which can be attributed to inefficient operations, are cause for concern if customers have access to alternative energy sources. Self-generation has been a risk, as large commercial and industrial customers may take advantage of cogeneration technologies to reduce their reliance on and in some cases to disconnect from the system. In the future, technology could pose a greater threat. Bypass risk, too, may grow if distributed generation, microgeneration, and self-generation prove more economically attractive for smaller customers.

Due to their proximity to interstate gas pipelines, some large customers can directly tie into a transmission line and completely bypass gas distributors' services. Although such pipelines provide key sources of gas supply for these companies, it is important to recognize this bypass risk. Ideally located gas companies have adequate transmission access but have industrial customers far from interstate pipelines.

Critical success factors include:

- Low cost structure,
- Limited bypass risk, and
- Management's commitment to lowering costs.

Management

Evaluating management is of paramount importance to Standard & Poor's analysis because management decisions affect all areas of a company's operations and financial health. Although regulation, the economy, and other outside factors certainly influence results, the quality of management ultimately determines a company's success. Standard & Poor's private meetings with senior management significantly augment the public record in the effort to appraise management. Meetings are very useful for the candid interpretation of recent developments and, importantly, to provide executives with a forum for the presentation of goals, objectives, and strategies.

Management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple—and often incompatible—priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

Standard & Poor's also focuses on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

In addition, a company's accounting and financing practices are critical to Standard & Poor's analysis. For example, proactive management will likely adopt accounting practices that are more appropriate in a competitive environment such as higher depreciation rates for electric generation equipment. Large, growing cost deferrals or regulatory assets are viewed more negatively. Management can enhance its financial condition by taking any number of discretionary actions, such as selling common equity, reducing the common dividend payout, and deleveraging. A utility's management will also be evaluated on cost-cutting ability and creativity in entering into strategic alliances that improve efficiency.

Strong corporate governance, reflected in active, independent boards of directors that participate in determining and monitoring corporate controls, helps to support management's credibility and corporate financial disclosure. If it is evident that a company's board is passive and does not exercise proper oversight, it weakens the checks and balances of the organization and may detract from credit quality. Included in Standard & Poor's review of corporate governance is the proportion of independent directors on the board, the breadth and depth of the directors' experience, the proportion of independent directors on the board's audit committee, and directors' compensation.

Some vertically integrated utilities have felt compelled to invest outside their traditional businesses to increase earnings, especially as stock prices have underperformed market indices. Participation in higher-risk, unregulated activities such as merchant generation, exploration and development, gathering and processing, or marketing and trading can significantly detract from the consolidated entity's credit profile. In this regard, credit ratings are not based on the regulated business only, but on the qualitative and quantitative fundamentals of the consolidated entity. Standard & Poor's considers the ratings of the regulated businesses as being less vulnerable to the negative credit influence of other affiliates and holding company activities, as relevant, where very strong structural and/or regulatory insulation exists, which tends to be more the exception than the rule.

Critical success factors include:

- Commitment to credit quality,
- Credibility,
- Strong corporate governance, and
- Conservative financial policies, especially regarding nonregulated activities, if relevant.

Effect On Ratings

In summary, Standard & Poor's examines the key business risk drivers for vertically integrated utilities—regulation, markets, operations, competitiveness, and management—in conjunction with financial measures when assigning credit ratings. The credit quality of most vertically integrated utilities is solidly investment grade. This is a primarily a function of the existence of regulation. As discussed above, the factors that further differentiate ratings among this sector include their markets, operational track record, competitive posture, and management's risk appetite. Vertically integrated utilities generally have satisfactory business risk profile scores, with only a few having strong or weak business positions. ■

Appendix

Table 1 Industry Benchmark Ranges

Business Profile	AA	A	BBB	BB
Adjusted FFO interest coverage (x)				
1	3.0-2.5	2.5-1.5	1.5-1.0	< 1.0
2	4.0-3.0	3.0-2.0	2.0-1.0	< 1.0
3	4.5-3.5	3.5-2.5	2.5-1.5	1.5-1.0
4	5.0-4.2	4.2-3.5	3.5-2.5	2.5-1.5
5	5.5-4.5	4.5-3.8	3.8-2.8	2.8-1.8
6	6.0-5.2	5.2-4.2	4.2-3.0	3.0-2.0
7	8.0-6.5	6.5-4.5	4.5-3.2	3.2-2.2
8	10.0-7.5	7.5-5.5	5.5 -3.5	3.5-2.5
9	N/A	10.0-7.0	7.0 -4.0	4.0-2.8
10	N/A	11.0-8.0	8.0 -5.0	5.0-3.0
Adjusted FFO/average total debt (%)				
1	20-15	15-10	10-5	< 5
2	25-20	20-12	12-8	< 8
3	30-25	25-15	15-10	10-5
4	35-28	28-20	20-12	12-8
5	40-30	30-22	22-15	15-10
6	45-35	35-28	28-18	18-12
7	55-45	45-30	30-20	20-15
8	70-55	55-40	40-25	25-15
9	N/A	65-45	45-30	30-20
10	N/A	70-55	55-40	40-25
Adjusted total debt/total capital (%)				
1	48-55	55-60	60-70	> 70
2	45-52	52-58	58-68	> 68
3	42-50	50-55	55-65	65-70
4	38-45	45-52	52-62	62-68
5	35-42	42-50	50-60	60-65
6	32-40	40-48	48-58	58-62
7	30-38	38-45	45-55	55-60
8	25-35	35-42	42-52	52-58
9	N/A	32-40	40-50	50-55
10	N/A	25-35	35-48	48-52

Note: Business profile scores are characterized from '1' (excellent) to '10' (weak). FFO—Funds from operations. N/A—Not applicable.

Table 2 **Vertically Integrated Utilities**

Company	Corporate credit rating	Business profile score
Aquila Inc.	B/CW-Pos/B-2	6
AGL Resources Inc.	A-/Negative/A-2	4
Alabama Power Co.	A/Stable/A-1	4
ALLETE Inc.	BBB+/Stable/A-2	5
Ameren Corp.	BBB+/CW-Neg/A-2	6
Appalachian Power Co.	BBB/Stable/—	5
Arizona Public Service Co.	BBB-/Stable/A-3	6
Atmos Energy Corp.	BBB/Stable/A-2	4
Black Hills Power Inc.	BBB-/Negative/—	6
Central Illinois Light Co.	BBB+/CW-Neg/—	7
Central Vermont Public Service Corp.	BB+/Stable/—	6
CILCORP Inc.	BBB+/CW-Neg/—	7
Cincinnati Gas & Electric Co.	BBB/Positive/A-2	6
Cleco Power LLC	BBB/Negative/—	6
Cleveland Electric Illuminating Co.	BBB/Stable/—	6
Consolidated Natural Gas Co.	BBB/Stable/A-2	6
Consumers Energy Co.	BB/Stable/—	6
Dayton Power & Light Co.	BB+/Positive/—	5
Detroit Edison Co.	BBB/Stable/A-2	6
Duke Power Co. LLC	BBB/Positive/A-2	4
El Paso Electric Co.	BBB/Stable/—	6
Empire District Electric Co.	BBB-/Stable/A-3	6
Energy East Corp.	BBB+/Negative/A-2	3
Enogex Inc.	BBB+/Stable/—	7
Entergy Arkansas Inc.	BBB/Negative/—	5
Entergy Gulf States Inc.	BBB/Negative/—	6
Entergy Louisiana LLC	BBB/Negative/—	5
Entergy Mississippi Inc.	BBB/Negative/—	6
Entergy New Orleans Inc.	D/—/—	8
Equitable Resources Inc.	A-/CW-Neg/A-2	8
Florida Power & Light Co.	A/CW-Neg/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Green Mountain Power Corp.	BBB/CW-Pos/—	5
Gulf Power Co.	A/Stable/—	4
Hawaiian Electric Co. Inc.	BBB+/Negative/A-2	5
IDACORP Inc.	BBB+/Negative/A-2	5
Idaho Power Co.	BBB+/Negative/A-2	5
Indiana Michigan Power Co.	BBB/Stable/—	6
Indianapolis Power & Light Co.	BB+/Positive/—	4
Interstate Power & Light Co.	BBB+/Stable/A-2	5
IPALCO Enterprises Inc.	BB+/Positive/—	4

Table 2 **Vertically Integrated Utilities** (continued)

Company	Corporate credit rating	Business profile score
Kansas City Power & Light Co.	BBB/Stable/A-2	6
Kansas Gas & Electric Co.	BB+/Positive/—	6
Kentucky Power Co.	BBB/Stable/—	5
Kentucky Utilities Co.	BBB+/Stable/A-2	5
Louisville Gas & Electric Co.	BBB+/Stable/—	5
Madison Gas & Electric Co.	AA-/Stable/A-1+	4
Michigan Consolidated Gas Co.	BBB/Stable/A-2	4
MidAmerican Energy Co.	A-/Stable/A-1	5
Mississippi Power Co.	A/Stable/A-1	4
Monongahela Power Co.	BB+/Positive/—	5
Montana-Dakota Utilities Co.	BBB+/Stable/—	6
National Fuel Gas Co.	BBB+/Stable/A-2	7
Nevada Power Co.	B+/Positive/—	6
New York State Electric & Gas Corp.	BBB+/Negative/A-2	3
NiSource	BBB/Stable/—	4
Northern Indiana Public Service Co.	BBB/Stable/—	5
Northern States Power Co.	BBB/Stable/A-2	5
Northern States Power Wisconsin	BBB+/Stable/—	4
Ohio Edison Co.	BBB/Stable/A-2	6
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	5
Pacific Gas & Electric Co.	BBB/Stable/A-2	5
PacifiCorp	A-/Stable/A-1	5
Pennsylvania Power Co.	BBB/Stable/—	6
Pinnacle West Capital Corp.	BBB-/Stable/A-3	6
PNM Resources Inc.	BBB/Negative/A-3	6
Portland General Electric Co.	BBB+/Negative/A-2	5
Progress Energy Carolinas Inc.	BBB/PositiveA-2	5
Progress Energy Florida Inc.	BBB/Positive/A-2	4
PSI Energy Inc.	BBB/Positive/A-2	4
Public Service Co. of Colorado	BBB/Stable/A-2	4
Public Service Co. of New Hampshire	BBB/Stable/—	5
Public Service Co. of New Mexico	BBB/Negative/A-3	6
Public Service Co. of Oklahoma	BBB/Stable/—	5
Puget Energy Inc.	BBB-/Stable/—	4
Puget Sound Energy Inc.	BBB-/Stable/A-3	4
Questar Market Resources Inc.	BBB+/Stable/—	8
Rochester Gas & Electric Corp.	BBB+/Negative/—	3
San Diego Gas & Electric Co.	A/Stable/A-1	5
Savannah Electric & Power Co.	A/Stable/—	4
SCANA Corp.	A-/Stable/—	4
Sierra Pacific Power Co.	B+/Positive/—	6

Table 2 **Vertically Integrated Utilities** (continued)

Company	Corporate credit rating	Business profile score
Sierra Pacific Resources	B+/Positive/B-2	6
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
Southern California Edison Co.	BBB+/Stable/A-2	6
Southern Co.	A/Stable/A-1	4
Southern Indiana Gas & Electric Co.	A-/Stable/—	4
Southwestern Electric Power Co.	BBB/Stable/—	5
Southwestern Public Service Co.	BBB/Stable/A-2	5
System Energy Resources Inc.	BBB-/Negative/—	7
Tampa Electric Co.	BBB-/Stable/A-3	4
Toledo Edison Co.	BBB/Stable/—	6
Tucson Electric Power Co.	BB/Stable/B-2	6
TXU U.S. Holdings Co.	BBB-/Negative/—	8
Union Electric Co.	BBB+/CW-Neg/A-2	5
Union Light Heat & Power Co.	BBB/Positive/—	5
Vectren Utility Holdings Inc.	A-/Stable/A-2	3
Virginia Electric & Power Co.	BBB/Stable/A-2	5
Westar Energy Inc.	BB+/Positive/—	5
Wisconsin Electric Power Co.	A-/Negative/A-2	4
Wisconsin Energy Corp.	BBB+/Negative/A-2	5
Wisconsin Power & Light Co.	A-/Stable/A-2	4
Wisconsin Public Service Corp.	A+/CW-Neg/A-1	4
Xcel Energy Inc.	BBB/Stable/A-2	5

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U.S. Utilities, Power, and Gas 2010 Outlook

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Related Research

- *Pipeline/Midstream/MLP 2010 Outlook, Dec. 3, 2009*

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Overview

The U.S. Utilities, Power, and Gas (UPG) sector 2010 outlook is framed in the context of Fitch Ratings' outlook for a slow U.S. economic recovery in 2010, with stable outlooks for most of the business segments within the UPG universe except for negative 2010 credit outlook for competitive generators and retail propane distributors. Forces driving the credit outlook are summarized below:

- Growth in power sales adjusted for weather will resume after the declines of 2008–2009. Natural gas sales volume is expected to be relatively flat year on year.
- Market prices for natural gas and electric power and capacity are likely to remain in a low band. Relatively low prices are:
  - Beneficial or neutral for electric and gas utilities.
  - Unfavorable for competitive power generators and natural gas storage and midstream services.
- While non-energy commodity prices are up from their trough in 2009, we do not foresee an overheated economy with rapid expansion in the prices of construction materials; however, U.S. dollar weakness is likely to raise costs of imported machinery and equipment, and could eventually raise prices of U.S. construction materials, increasing capital investment cost pressures.
- Electric utilities reduced their 2010 capital expenditure budgets from earlier planned amounts, but the overall level of investment remains greater than internal funding and will require external financing, including raising equity capital.
- Continued good access to debt and equity capital markets is expected, along with gradual improvement in bank market conditions.
- Electric and gas utilities are in a long-term cycle of rising unit costs, requiring frequent base rate increases to maintain stable financial results.
- While Fitch expects that most utilities will achieve reasonable regulatory outcomes, the dependence on rate increases exposes utilities to potential resistance from regulators, state politicians, and consumers/voters.
- Fitch expects passage within two years of national laws limiting greenhouse gas (GHG) emissions and possibly a national renewable portfolio standard, as well as more stringent environmental regulations on other emissions. This will have little effect on cash flow in 2010, but longer-term consequences for many competitive power generators are unfavorable, especially for owners of coal-fired generation, and it will add to cost pressures for integrated electric utilities and their consumers.

The "Credit Outlook Summary by Segment" table on page 2 of this report delineates the outlook and median rating with supporting bullet points for each business segment in the UPG sector. Fitch's business segment outlooks are formulated based on an analysis of fundamental factors, not by tallying the current rating outlooks of individual issuers in the business segment. Rating Outlooks for individual companies often vary from segment outlooks due to the specific circumstances of each entity. As of Dec. 1, 2009, more than 86% of individual issuer Rating Outlooks in the UPG sector are Stable.

Resilient Performance in 2009

Companies in the UPG sector weathered the recession and financial crisis of 2008–2009 with considerably less pain than sectors such as financial institutions, cyclical industrials, and retailers. The absence of significant defaults in the sector is in stark contrast to the upswing in defaults and bankruptcy filings across the rest of the U.S.

Credit Outlook Summary by Segment

The 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 2010
Utility Parent Companies Median IDR: BBB **Credit Outlook** Stable (One Year) Negative (Longer Term)	• Continued cost cutting for earnings and cash flow growth. • Investment focus on organic growth, investments in transmission, and renewables. • M&A activity will be limited. • Focus on core businesses; selective divestitures. • Equity issuance needed to maintain balanced capital mix.
Electric Utilities, Investor-Owned Median IDR Integrated Electric: BBB Median IDR Electric Distribution: BBB **Credit Outlook** Stable (One Year) Stable to Negative (Longer Term)	• Sustained high capital spending for the majority of companies. • Relatively low gas and power prices will mitigate effect of rising infrastructure costs in 2010. • Rising unit costs longer term due to new infrastructure and carbon regulations. • Serial base rate cases to recover infrastructure investments in 2010 and longer term. • Significant new debt, hybrids, and equity issuance to fund capex.
Gas Distributors, Investor-Owned Median IDR: A– **Credit Outlook** Stable (One Year and Longer Term)	• Oversupply of gas into the 2010 winter season will relieve rate pressure. • Sales growth constrained by continued weakness in the housing sector. • Capital expenditures will remain fairly low and manageable. • Expect consistent regulatory treatment and manageable external funding.
Competitive Generation Companies **Generating Companies and Energy Trading** Median IDR: BB– **Credit Outlook** Negative (One Year) Negative to Stable (Longer Term)	• Excess power reserve margins will linger with modest demand growth. • Low gas and power price environment will hold down margins for most generators. • Need to replace expiring hedges and contracts in a weak pricing environment. • Uncertainty surrounding carbon legislation remains a key operating and credit issue for this group.
Natural Gas Midstream Companies **Midstream and Pipeline Companies** Median IDR: BBB– **Credit Outlook: Pipelines** Stable (One Year and Longer Term) **Credit Outlook: Midstream** Stable (One Year and Longer Term) **Credit Outlook: Propane** Negative (One Year and Longer Term)	• Development of low-risk, contractually supported pipelines to connect increased shale gas production to high-demand eastern markets. • Midstream processing volumes and margins likely to be supported by significant price advantage of NGLs over oil-based naptha as ethylene feedstock. • Modest increase in volumes on natural gas and refined products pipelines due to recovering economic activity. • Companies are likely to continue to pursue conservative financial practices.
Public Power Utilities **Municipal, State, and Federal Agencies and Cooperatives** Median Rating[a] (Retail Systems): A+ Median Rating[a] (Wholesale Systems): A **Credit Outlook** Stable (One Year) Stable to Negative (Longer Term)	• Benefit from less state regulatory oversight; local control over rate-setting. • Continued lower usage and decreased revenues from surplus power sales anticipated for 2010. • Growing pressure for local governments to slow rate increases and boost transfers from the utility system to replace lost city tax revenue and fund pension obligations. • Generation investment will continue, albeit at a slower pace. • Rising unit costs longer term due to new infrastructure and carbon regulations. • Improving access to third party liquidity; expect extension of federal stimulus program which provides for issuance of taxable Build America Bonds by municipal entities.

[a]Median ratings shown for Public Power Utilities are senior unsecured debt ratings.
Source: Fitch.

economy, consistent with the defensive reputation of the sector.

In general, companies in the UPG sector entered 2009 in reasonably sound financial condition; some drew down their bank credit facilities during the banking crisis in late 2008 and repaid the loans as the bank and financial markets stabilized during 2009.

Rate-regulated utilities benefited during the market disruption from bond investors' preference for low-risk infrastructure investments. Regulated utilities and holding companies with higher investment-grade ratings had adequate to robust bond and commercial paper market access throughout 2009, and the bond market became more open to funding companies with speculative-grade ratings at progressively lower spreads during the second half of 2009.

Electric and gas utilities' sales volumes were reduced as a result of cyclical sales declines, especially lower industrial consumption of gas and power, with greatest impact in the Midwest. Residential demand was also lower, particularly in markets with the greatest impact from the housing collapse. While reduced sales hurt cash flow, lower costs of natural gas and power purchases, combined with timing differences in cost recoveries and collections of prior fuel deferrals, helped support operating cash flow and reduced working capital needs. Some integrated electric utilities that rely on spot sales of excess power into the wholesale market and rely on profits from wholesale sales suffered from a material decline in spot market prices.

Competitive generators and midstream gas processors were exposed to oversupply of natural gas and declines in power and gas spot and forward prices to the extent production was unhedged. However, generators and midstream processors that entered 2009 with their sales significantly hedged avoided most of the impact of lower margins.

Key Drivers of the 2010 Outlook

Fitch's 2010 credit outlook for the Utilities, Power, and Gas sector incorporates the following framing economic and capital market assumptions:

- General economic recovery continues over the course of 2010.
- Capital market conditions are expected to be open and the bank market to have a gradual improvement in spreads.
- Interest rates are expected to rise over the course of the year from very low levels.
- Weather-adjusted power demand expected to return to growth in 2010–2011. Power is expected to form a longer-term growth trend averaging about 1.4% to 1.6% per annum. Recovering industrial and commercial demand for natural gas should offset increased efficiency, resulting in flat sales overall for gas.

Fitch's 2010 U.S. economic outlook is for a slow recovery, with a projected modest 1.8% rise in GDP. Industrial production and GDP appear to be gaining, albeit from a low base. Fitch expects the pace of expansion to remain weak by the standard of prior recoveries. While job losses are slowing, unemployment is not improving, and could weigh on consumer sentiment and spending for several quarters. While there is a risk of a double-dip recession, which would continue to suppress sales growth in the sector and would result in a more adverse near-term credit environment, this is not Fitch's base case.

Interest Rates

U.S. Treasury interest rates in 2009 were at historically low levels, with short-term rates near zero for the first half of the year. Later in 2009, the long end of the yield curve began to move up. In the low rate environment, utilities achieved low-cost long-term debt financing, with 20- to 30-year taxable utility operating company issues at 5.50%–6%. As long as U.S. Treasury policy keeps rates low, the dollar would remain under pressure. Assuming that the economic recovery takes hold, the Federal Reserve would have to devise an exit from its easy-money monetary policy, allowing short-term interest rates to revert to a more normal level, and long-term rates to move up as well.

Access to Capital and Credit Markets

Access to the debt capital market is expected to remain open to the UPG sector issuers in 2010–2011.

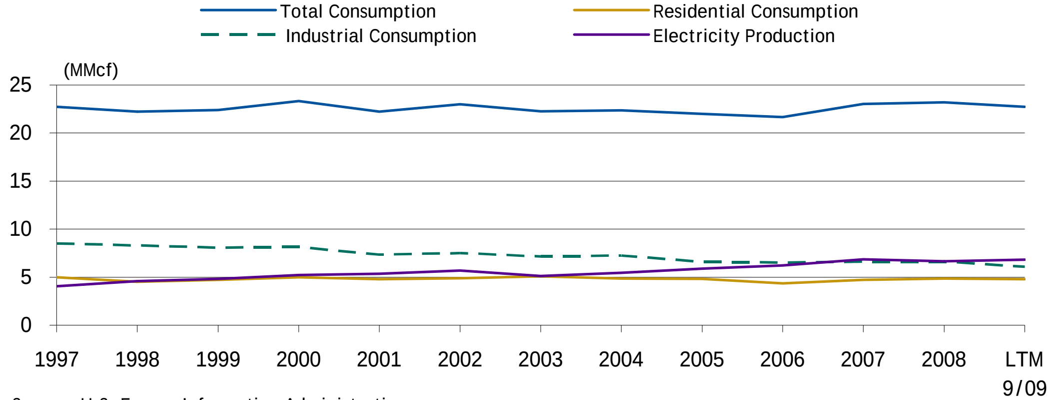
Access to equity capital in addition to debt will be critical for utilities and utility holding companies to maintain stable credit profiles, given the forecast for capital expenditures in the sector in excess of internal cash flow. The utility sector will have difficulty to satisfy equity investors' expectations for growth in a general economic recovery. Companies with strong market valuations or better growth fundamentals are better positioned to raise equity without excessive dilution. Many utilities are considering the use of hybrid securities to minimize dilution.

Fitch is monitoring expiring bank credit facilities and the pricing, covenants and terms of new and replacement facilities. A recent Fitch study tallied approximately $163 billion of credit facilities of companies in the UPG sector expiring in 2010–2014, with approximately 40% ($65 billion) of maturities concentrated in 2012. Fitch concluded that expiring credit facilities are not likely to create a liquidity issue for the sector, although credit costs are likely to be higher than prior to the credit crisis. Fitch expects that companies with expiring credit facilities will close the gap by means of alternatives such as diversifying credit providers and using new types of credit facilities, relying more on capital market debt and less on bank facilities for direct funding or back-up, and altering collateral-intensive business practices to reduce needs for back-up credit. (*For more on this topic, please refer to "Fitch Review of Bank Credit Facilities in the Utilities, Power, and Gas Sector," published on Oct. 28, 2009.*)

Gas and Power Demand

The trend over the past decade has been for declining natural gas consumption by industrial users to be offset by higher usage for power generation. In 2009, extremely low natural gas prices caused the dispatch of gas combined-cycle units to displace some production by less-efficient coal plants. Assuming somewhat higher gas prices in 2010, gas is likely to give back some share to coal at the margin. Beyond 2010, Fitch expects

U.S. Natural Gas Consumption by Customer Sector

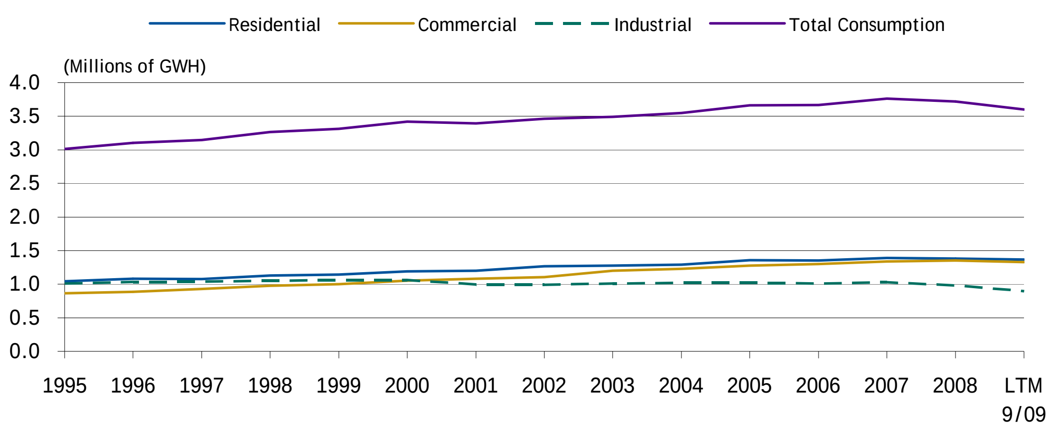


Source: U.S. Energy Information Administration.

that use of natural gas for power generation will be growing and taking share away from coal, offsetting shrinkage in primary demand for gas as a fuel for residential, commercial, and industrial applications. On balance, weather-adjusted sales of natural gas are forecasted to be approximately flat.

On a weather-adjusted basis, Fitch expects that U.S. electricity sales will rise in 2010 by 1% to 2%, largely due to a rebound in industrial usage straddling 2010–2011 that would recover some but by no means all of the industrial demand lost in 2008–2009. Longer run, Fitch foresees U.S. power consumption growing at 1.4%–1.6% annually. Growth in U.S. per capita electricity consumption has been in a long-term secular decline since 1960, and that trend is likely to continue as state and federal policies increasingly favor energy-efficiency and demand-reduction programs. In those states with aggressive policies promoting demand reduction, electric utilities are likely to press for tariff decoupling mechanisms to replicate those already in effect for many natural gas distributors and in a few jurisdictions for electricity.

U.S. Electricity Consumption by Customer Sector



Source: U.S. Energy Information Adminstration.

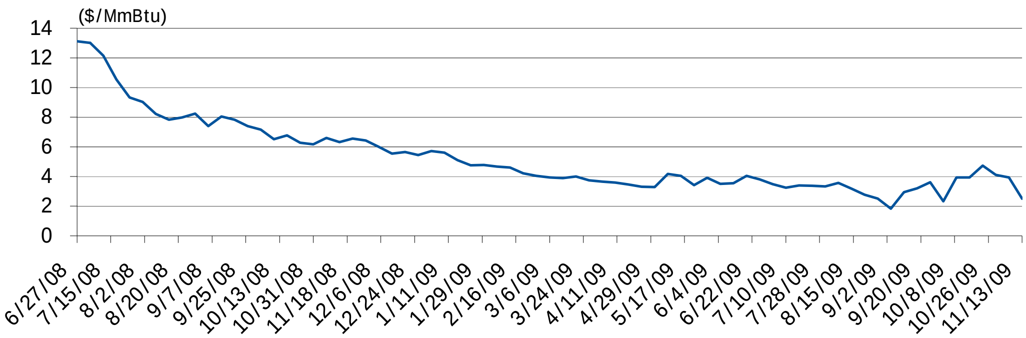
Commodity Prices

While market prices of gas and electric power are expected to rise from the 2009 trough, prices are likely to remain well below the levels that prevailed in early 2008. Relatively low gas and power prices are a favorable element in the credit outlook of most electric and gas distribution utilities and many integrated electric utilities, but form a more challenging market environment for competitive generators with conventional power generation assets and midstream gas processors to the extent that sales are dependent on market prices rather than contracts signed at more favorable prices.

Producers of steam coal remain in a pinch between their own rising production and pension costs and the gas-on-coal competition at the margin for power production. Coal stockpiles at power plants will enter 2010 materially above historical levels. While demand and prices for met coal can rise with global economic recovery, steam coal prices are likely to be constrained.

Prices of steel, cement, and other construction materials are up somewhat from their trough in early 2009, and prices are expected to increase over the course of 2010, especially due to the weak U.S. dollar. However, we see no basis for a return in 2010 to the runaway inflation of construction materials of early 2008.

Natural Gas Spot Prices — Henry Hub



MmBtu – Million British thermal units.
Source: Bloomberg.

Natural Gas Price Environment

Natural gas supply has exceeded demand for much of 2009, reflecting a combination of lower consumption, high production, and historically high gas inventory levels. Rapid expansion of shale gas production as well as greater accessibility to Rockies' gas production contributed to the 2008–2009 collapse of U.S. gas prices as the recession depressed industrial demand. Fitch believes that price weakness will continue throughout 2010 as the industry works through high inventory levels and demand remains weak; the dramatic reduction in rig count during 2009 may only gradually reduce the gas oversupply, especially since new shale production tends to have very high initial production levels.

Weather is a dominant factor in natural gas demand in the residential and commercial markets. Fitch does not forecast the weather; however, given the drops in natural gas demand in the industrial sector of the economy, it is not clear that even a colder-than-normal winter would be enough to support materially higher natural gas prices in 2010.

Wholesale Electricity Prices

As a result of the decline in U.S. power consumption in 2009 along with some new power capacity coming on line, capacity reserve margins have increased to the extent that all U.S. power regions are currently oversupplied, with capacity reserve margins in excess of 30% in most regions. Additions of renewable resources (largely wind) and a few large coal plants that came on line in 2009 or will enter service in 2010 also tend to prolong the industry overcapacity. Excess power capacity will only gradually be absorbed by the modest increase in power demand.

The relatively low band of natural gas prices foreseen for 2010–2011 is expected to combine with high capacity reserve margins to keep electric power and capacity prices in a moderately low range in 2010 compared with the prices that prevailed in 2007 through mid-2008. Increasing output of wind and solar generation over the next several years will also play a role in reducing round-the-clock energy prices and market clearing heat rates, especially in those markets with the most abundant resources of wind (Midwest and Plains, Texas) if transmission is adequate to move power to load centers. In 2010–2013, 30% or more of the new power generation coming on line in the U.S. will be wind, solar or other renewable generation, stimulated by tax subsidies, state renewable portfolio standards, and feed-in tariffs in some states. Finally, construction of new electric transmission facilities in New England and PJM and in ERCOT over the next five years is expected to begin to lower electricity prices in congested zones and to raise prices outside the congestion zones.

Capital Expenditures

Overall, companies in the UPG sector responded to the recessionary environment and reduced gas and power demand by deferring capital expenditures (capex) budgeted for 2009 and 2010 or cutting out discretionary projects, but the effects differ by segments within the sector. Overall, capex in the sector will remain well in excess of depreciation charges relating to the existing asset base.

- Capex for the competitive power generation sector remains in excess of depreciation charges, despite more limited access to capital by the independent generators as well as the court overturn of the Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) regulations, which caused some companies to delay environmental compliance projects. In 2010, capex will include more environmental compliance work, investments in renewable power sources that carry abundant tax incentives and up-rates of existing nuclear plant capacity.
- Constrained by uncertain access to capital, gas midstream companies, and master limited partnerships (MLPs) reduced capex very sharply in 2009, cutting back to maintenance levels and completion of major projects already under construction. Some major pipeline infrastructure projects are under construction, and these have put some stress on credit ratios of their sponsors. In 2010, companies will spend to complete major pipeline projects and to extend gathering lines to new shale-producing areas, and could ramp up discretionary capex if funding is available and market conditions improve with enhanced economic activity.
- Gas distribution utilities generally have modest capex budgets, averaging around 1.5x annual depreciation charges. Spending is expected to decline year on year in 2010.
- Electric utilities have been in a pattern of increasing capex from 2005–2008 and had budgeted to continue to grow in 2009. In 2009, the investor-owned electric utilities reduced their aggregate capex by 10% from the originally budgeted 2009 levels, and cut their 2010 plans by 9% from the original plans for 2010. After those cuts, 2010 capital expenditures for the segment as a whole are now budgeted to be essentially flat with the record $84 billion level of 2008, and Fitch expects to see some growth in capex in 2011. The ratio of capex to annual depreciation and amortization charges will on average be higher for integrated utilities than for utilities that are pure transmission and distribution (T&D) providers. Fitch notes that there is considerable divergence in capital investment among the T&D utilities, including some that are investing heavily for advanced metering or transmission and grid reliability projects and several with very minimal capex. (*For more information on this topic, please refer to "Electric Utility Capital Expenditures: The Show Will Go On," published on Oct. 14, 2009*).

Ratio of Capital Expenditures to Depreciation and Amortization
(12 Months Ended Sept. 30, 2009)

	Average	Minimum	Maximum
Parent Companies (Consolidated)	2.3	0.7	4.9
Electric Integrated Utilities	2.7	0.8	6.7
Electric Distribution Utilities	1.5	0.3	4.6
Gas Distribution Utilities	1.5	0.9	3.0
Competitive Generators	2.8	0.9	7.0
Pipeline and Midstream Gas	2.5	1.0	7.6

Source: Fitch Ratings, company financial statements.

Public Policy Will Drive Fundamental Changes

While it is still uncertain whether a major energy bill will be enacted in 2010, the presidential administration and Congressional leadership are intent upon enacting a law to address climate change, including limits on GHG emissions using a cap-and-trade program, implementing standards for energy efficiency and conservation, and promoting investments in renewable resources. However, it has so far proven difficult to find bipartisan support or to muster sufficient support within the Democratic majority to pass a Senate bill that will raise costs for consumers and disadvantage some states more than others.

If the Congress is unsuccessful in passing new laws on these matters, the EPA has the authority to take a more vigorous approach to carry out the federal court mandate defining carbon dioxide and other GHGs as dangerous pollutants subject to regulation under the Clean Air Act. Compliance with an EPA rule is likely to be more difficult and costly for electric power generators and integrated utilities than a compromise bill crafted by Congress; thus, the electric industry has united to support Congressional action. Also, EPA is expected to act on new regulations to replace vacated Clean Air Interstate Rule and Clean Air Mercury Rule with important effects on coal-fired generating units, though not likely to have material effect in 2010.

Fitch assumes that there will either be a national law within the next two years that will regulate carbon emissions, or the EPA will step in with new regulations with more severe impact. If the EPA establishes rules, they are likely to take several additional years of litigation and implementation. Fitch conducts sensitivities of the effects of possible emissions prices or a tax on carbon emissions in its credit reviews of power generators, but has not developed stress cases around potential EPA regulations.

Renewable Energy and Technology Innovation

Roughly half the states have adopted renewable portfolio standards (RPS) requiring utilities to source a larger share of their electric power from defined renewable sources, and more continue to jump on the bandwagon. There is growing pressure in some states to establish feed-in tariffs and/or net metering of electricity. The longer-term effect of these requirements may be adverse for electric utility credit if utilities become loaded up with costly and inflexible power purchase obligations, akin to the problems that occurred in the 1980s–1990s following the implementation of the Public Utility Regulatory Policy Act of 1978. As higher costs of renewable resources and related transmissions are pushed into consumer tariffs, it could make it more difficult for utilities to achieve base rate increases to recover other rising cost elements and maintain satisfactory equity returns.

In 2009, significant tax incentives (*see the Federal Tax Matters section on page 9*) have begun to stimulate a sharp increase in investments in wind, solar, biomass, and other resources defined as renewable power. Federal loan guarantees for renewable resources, advanced clean energy technologies, and electric transmission, as well as grants from the Department of Energy for advanced metering and Smart Grid projects are additional sources of stimulus.

We have entered a period of high technology innovation in renewable energy resources, demand reduction, energy efficiency, and electric power transmission networks. A significant amount of work is underway to prepare for potential charging of plug-in electric vehicles, a development that would require substantial new investments in the utility distribution grid. The industry is testing technologies for carbon capture and storage, integrated gasification with combined cycle electric production (IGCC), battery storage, and pursuing licensing of new nuclear reactor designs. The U.S. has increased federal funding for energy-related research at the national laboratories. Burgeoning and often conflicting policies and technology changes will lead to fundamental and largely unpredictable changes in the energy and electricity sector over the next five to 10 years, but with relatively small impact in 2010.

Federal Tax Matters

Many companies in the UPG sector will lower their tax bills for 2009 and 2010 as a result of a host of economic stimulus tax provisions. Tax credits for investments in renewable energy and extended tax loss carry-backs will temporarily turn the tax return into a profit center for several companies in the sector.

The American Recovery and Reinvestment Act of 2009 (ARRA), an economic stimulus package, extended and expanded tax benefits available to specific project investments, particularly for various renewable energy technologies:

- **Renewable Energy Production Tax Credits (PTC):** ARRA extended eligibility dates of a tax credit for facilities producing electricity from wind, biomass, geothermal energy, municipal solid waste, and qualified hydropower and marine renewable energy. The "placed in service date" for wind facilities was extended to Dec. 31, 2012, and for the other types of facilities to Dec. 31, 2013.
- **Election of Investment Tax Credits in Lieu of PTC:** Businesses that place in service facilities that produce electricity from wind and some other renewable resources can choose either the energy investment tax credit (generally a 30% tax credit for investments in energy projects) or the PTC, which provides a credit per kWh for electricity produced from renewable sources. A business may not claim both credits for the same facility. A taxpayer electing the ITC in lieu of PTC receives a cash payment 60 days after achieving the commercial operation date.
- **Bonus Depreciation:** Businesses can deduct half the adjusted basis of qualifying property in the year it is placed in service. The extension applies to qualifying property placed in service in 2009 (2010 for long production period property and certain transportation property).

Net operating loss (NOL) carry-back was extended for a maximum carry-back of 5 years rather than the normal two-year period applicable to nearly all companies, except for recipients of TARP relief, as a provision of the Homeownership and Business Assistance Act of 2009 (November 2009). The carry-back can be applied to NOLs generated in either 2008 or 2009 but not for both years. The effect is an immediate increase in available cash for the taxpayer.

Meanwhile, the prior administration's dividend tax cut is scheduled to expire at the end of 2010, and there is wide speculation that additional taxes or higher tax rates will be applied to fund the federal deficit, including eliminating the current favorable treatment of capital gains and dividend income. Given the sector's heavy capex requirements, Fitch would consider any such changes in federal income and capital gains tax rates to be unfavorable developments that would likely lower equity valuations of regulated utilities and utility holding companies.

Pension Funding

Many companies that entered 2009 with severe erosion in the value of their pension funds relative to projected benefit obligations opted to make cash contributions to comply with the U.S. Pension Protection Act of 2006, as moderated by the Worker, Retiree, and Employer Recovery Act of 2008. Cash contributions in 2009, combined with the recovery in bond and stock market values, have reduced the gap, but a number of companies will need to continue cash contributions in 2010 (absent a significant run-up in market values of investments).

Bankruptcy and Restructuring

There were no notable defaults or bankruptcy filings in the UPG sector in 2009. That stands in sharp contrast to the upswing in defaults and bankruptcy filings in other corporate sectors as a result of the severe national and global recession. A peak default period in the UPG sector was from 2001–2003.

SemGroup restructured and emerged from bankruptcy as a new public company in early December 2009, approximately 16 months after the company and its major wholly owned subsidiaries filed a bankruptcy petition on July 22, 2008. Pre-petition lenders were estimated to recover 100% on some secured obligations and secured trading exposures, an estimated 55% on one secured working capital loan facility, and 75% on a secured revolving credit. Unsecured lenders and general creditors were estimated to recover 5% to 10% of their exposure via the allocation of 5% of the equity in the new public company to the unsecured class.

SemGroup's 2008 insolvency resulted from its inability to post required margin collateral to trading counterparties. The company adopted a trading strategy based on the sale of naked call and put options that did not adhere to the SemGroup risk management policy and violated the terms of its pre-petition credit agreement. When SemGroup experienced trading losses, it increased and rolled forward its options positions, causing increased losses and occasioning growing demands for margin collateral that the company could not satisfy.

Utility Parent Companies

2010 Outlook — Stable
Longer-Term Outlook — Negative

The utility parent companies (UPCs) are poised for an improved economic and financial environment as compared to that of a year ago. With economic activity picking up, industrial sales have shown signs of stabilization in the third quarter. As industrial sales recover, it is likely that the commercial sales, which have been weak in certain regions, could follow suit. However, with revenue growth rates well below historical levels, Fitch expects UPCs to continue their cost-cutting focus in both their regulated and unregulated businesses to drive earnings and cash flow growth or support stability.

UPCs have withstood the credit crisis well. Overall, the companies were in a financially sound situation before the credit crisis hit, and liquidity during 2009 was bolstered by reduced working capital needs due to falling commodity prices, reduction in discretionary capex, and capital market issuances. Access to capital markets remains open and relatively low cost for creditworthy borrowers. Fitch expects UPCs to extend their conservative balance sheet stance in 2010, given the current fragile nature of economy and recovering credit markets, combined with the stated intentions of most management teams to maintain a stable credit profile. For regulated businesses, Fitch expects the utility parent companies to use a judicious mix of debt and equity to finance high levels of planned investments, most of which is mandated and earmarked for reliability, environment compliance, and renewable energy projects. For unregulated businesses, UPCs will need to balance the capital structure against rising business risk due to lower cash flows brought on by a fall in commodity prices and increasing proportion of unhedged output in the outer years.

Fitch expects climate change to remain a predominant focus for most UPCs despite the uncertainty around the contents and timing of passage of a national law. While some UPCs have been more proactive than others, Fitch expects more and more companies to pursue low/zero carbon technologies more aggressively than before. This could be manifested in both regulated and unregulated businesses investing a greater proportion of total capex in clean technologies and renewable generation as well as associated transmission, energy efficiency, and smart grid investments, and in retirements of older coal-fired power plants that cannot be economically retrofitted.

Parents of utilities are generally taking advantage of opportunities to invest in regulated rate base, driven by legislative/regulatory mandates as well as a strategic pursuit of cleaner technologies as highlighted above. Fitch expects UPCs to seek out those investment opportunities where prospects of cost recovery are high and the prospect is for a reasonable return on equity (ROE).

As of late November 2009, utility stocks as measured by the Philadelphia Utility Index (UTY) have declined 3% in 2009 and underperformed the S&P 500 by 18%. The increase in risk appetite among investors clearly worked against the defensive utility sector as signs of economic recovery emerged. Utility stocks that have a greater proportion of unregulated businesses have lagged their regulated peers due to a sharp fall in commodity prices. The sunset of reduced dividend tax rates on Dec. 31, 2010 further reduces the investment appeal of utility equity and is expected to increase the cost of equity capital.

Notwithstanding the turmoil in the economy and the adverse capital market conditions, especially in the early part of 2009, ratings in the UPC sector have remained generally stable. The UPC's median 'BBB' issuer default rating (IDR) and senior unsecured ratings are the same as a year ago. Year to date, there have been three upgrades and seven downgrades in the sector. Approximately 82% (37 of 45 observed companies) of Fitch's UPC issuers have Stable Rating Outlooks and 16% (seven of 45) have Negative Outlooks, while only 2% (one of 45) has a Positive Outlook.

Sector downgrades in 2009 reflect a challenging operating and financial environment due to both weak industrial sales and rising operating costs (NISource Inc.; IDR 'BBB–'/Stable), financial pressure, and associated execution risk from plans to build new nuclear plants (SCANA Corp.; IDR 'BBB+'/Stable), weak commodity prices, and lower profitability of the unregulated generation portfolio (PEPCO Holdings Inc.; 'BBB'/Negative), and reassessment of financial and liquidity risk (Constellation Energy Group, Inc. (CEG); 'BBB–'/Stable) among others. Fitch upgraded only three IDRs of parent holding companies in 2009. Two reflected gradually improved financial ratios and favorable state regulatory developments (Avista Corp.; IDR 'BBB–'/Stable and DPL Inc.; IDR 'A–'/Stable), and one resulted from demonstration of support by a foreign parent (Energy East Corp.; IDR 'BBB+'/Stable).

Ratings are not anticipated to change meaningfully in 2010. Fitch expects the overall ratings for the UPCs to be stable primarily due to modestly rising economic activity, and managements' relatively conservative financial and business strategies. Concerns would be a fall in economic activity and power demand, an increase in populist regulatory decisions, volatile commodity prices, adverse climate change mandates, and shareholder-friendly decisions that result in increased leverage.

Mergers, Acquisitions, and Divestitures

Fitch expects limited merger & acquisition (M&A) activity in the near term given uncertainties that remain around economic recovery, commodity prices, state regulatory responses, and carbon legislation, combined with the high costs of bank financing and relatively low equity valuations. Exelon Corporation's (EXC) failed bid to acquire NRG Energy, Inc. (NRG) in 2009 highlights the difficulty in pulling off a hostile deal. The ongoing delay for Entergy Corp.'s spinoff of Enexus is reflective of the difficult state regulatory environment related to M&A activities. Electricité de France's investment in a 49.99% joint venture interest in Constellation Energy Group's nuclear fleet was consummated late in 2009, after a controversial state regulatory proceeding that highlighted the regulatory hazards of merger/divestiture activity. That said, the case for industry consolidation remains strong given the fragmented industry, the scale of capital investments needed relative to the size of the companies, and the potential for operational synergies to drive down rates for consumers.

Fitch expects a majority of the UPCs to focus on organic growth, especially as regulated businesses take advantage of the attractive incentives for renewables and transmission development to drive rate base growth. As demands on capital increase, some UPCs could shed non-core assets, including businesses that are collateral intensive.

On the unregulated generation side, while there are good arguments for consolidation of smaller gencos, we see greater potential for asset acquisitions given low valuations. This could be driven by unregulated generators seeking "tuck-in" acquisitions or utilities short of generation seeking to grow their rate base. An emerging trend seems to be for unregulated generators to acquire renewable assets, such as the recent announcements by NRG to acquire an offshore wind developer and a solar farm in California and CEG to purchase wind assets in Maryland. It is quite possible that different forms of partnerships develop between traditional utility companies and the new generation clean technology companies to exploit relative strengths. Finally, a weaker dollar could spur cross-border asset acquisitions by foreign buyers or joint venture investments with foreign participants. Notable recent announcements of cross-border partnerships are AES Corporation selling a 15% stake to China Investment Corporation and Duke Energy signing agreements with several Chinese companies to develop a variety of renewable and clean energy technologies.

Electric Utilities

2010 Outlook — Stable
Longer-Term Outlook — Stable to Negative

Fitch's near-term outlook for the utility sector is stable, despite some challenges. The combination of high capital expenditures and relatively weak electricity demand will continue to pressure credit quality and require base rate increases in 2010 and beyond. Favorably, most regulated utilities are entering 2010 on sound financial footing. Moreover, overall rate pressures are mitigated by low fuel prices, strong capital market access, and low interest rates. Fitch's stable outlook assumes most states will continue the constructive regulation of recent years. However, given the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects.

Regulation

Decisions by state regulators will continue to be a key driver of individual company credit ratings in 2010. In general, state regulation is likely to continue to be even-handed; however, there could be isolated cases of adverse regulatory or politically motivated decisions on utility rates in an election year, which is considered to be event risk rather than a sector trend. Positively, low fuel costs should largely offset the impact of rising base rates in 2010. However, even with modest electricity demand growth next year, total customer demand is expected to remain below 2007 levels, and under-earning seems likely, even in the case of some companies that have base rate cases decided in 2009 and 2010. Some of the rate requests filed in late 2008 or early 2009 and still pending were made prior to the recognition of the full impact of recessionary load loss on demand; consequently, utilities are already playing catch up by seeking ways to cut operating costs and/or defer capex.

Numerous electric utilities have filed for base rate increases to recover costs of investments in system growth and reliability, as well as to adjust the allocation of operating and maintenance costs and capital recovery to lower demand levels. In addition, a number of multi-year rate settlement periods will end, enabling these utilities to deal with the rising costs and loss of load. Numerous state commissions are expected to reach decisions on new base rates in 2010. (*See the "Electric Rate Case Pending 2010 Decision" table below.*)

Electric Rate Cases Pending 2010 Decision

Arizona Public Service Company	Indiana Michigan Power Company
Atlantic City Electric Company	Monongahela Power Company
Black Hills Power, Inc.	New York State Electric & Gas Corp.
Central Hudson Gas & Electric Corp.	Northwestern Corporation
Connecticut Light and Power Co.	PacifiCorp
Consolidated Edison Co. of New York[a]	Potomac Edison
Delmarva Power & Light Co.	Potomac Electric Power Company
Duke Energy North Carolina	Public Service Co. of New Hampshire
Empire District Electric Company (MO and AK)	Public Service Electric and Gas Co.
Florida Power and Light Co.	Rochester Gas and Electric Corp.
Florida Power Corp.	Southwestern Electric Power Company (AK and TX)
Georgia Power Company	Union Electric Co.
Illinois Power Company	Western Massachusetts Electric Co.

[a]A settlement proposal is pending.
Source: C Three Regulatory Database, Fitch Ratings.

An emerging regulatory trend for integrated electric utilities is the initiation of electricity revenue decoupling in response to the recent softness of demand and state policies that include ambitious energy-efficiency targets. Tariff mechanisms that mitigate the effect of variances in sales are common among gas utilities, which have experienced declining demand for many years and whose sales have an extreme weather sensitivity; in gas distributors, this may take the form of minimum bills that recover a large part of fixed costs, fixed/variable tariff components, or explicit weather normalization or volume decoupling mechanisms. While such tariffs have not been common for residential consumers of electric utilities, Fitch sees states beginning to implement some mechanisms of this sort on the electric side, although in a few cases at a pilot scale. States that allow or initiated electric decoupling programs include: California; Ohio (Ohio utilities can request decoupling under existing rules), Vermont, New York (Consolidated Edison of NY, Orange & Rockland Utilities, Central Hudson Gas and Electric), Maryland (Baltimore Gas & Electric); and pilot scale programs in Wisconsin and Idaho. In Fitch's view, volume decoupling reduces cash flow volatility and lowers business risk, and will be particularly meaningful in states that have set aggressive energy reduction goals.

For electric T&D utilities in states that restructured their electricity markets, staggered power auctions or other competitive power procurement processes are becoming more customary and standard. Staggered contracts for up to three years create realized prices that are a blend of past and future prices, which moderates single-year commodity price volatility for customers. Most states that deregulated generation supply have already completed or are nearing completion of full transition to market-based generation rates. Solicitations for energy, capacity, and/or other services in the next six months are expected to include Duquesne, Metropolitan Edison/Penelec, Penn Power, PPL Electric Delivery, Philadelphia Electric Co., Illinois Power Agency, West

Penn Power, and the New Jersey Basic Generation Service auctions for the state's electricity utilities. While in prior years' outlooks, Fitch noted significant uncertainty regarding the ability of electric T&D utilities to obtain full and timely pass-through of generation costs in tariffs, this risk has subsided as auctions that place the price risk with consumers have become routine; the significant decline in wholesale market power prices has also helped to make the transition less controversial than in prior years.

Capital Spending

While many utilities responded to the economic downturn and court decisions that set aside the CAIR and CAMR by reducing or deferring capital spending budgets for 2009 and 2010, capital spending remains high relative to historical trends. In many cases, utility managements responded to weak demand by adjusting budgeted expenditures to accommodate lower demand curves and deferring, but not cancelling, new generation projects; however, projects to enhance distribution reliability generally were not delayed. Despite these deferrals, Fitch forecasts spending will continue to run at more than double depreciation on average. To fund the system investments, internal cash flow will need to be supplemented with external capital, and management will face choices of increasing leverage or shoring up the capital structure with new equity issuance.

Drivers of 2010 capital spending levels for electric utilities include: increasing environmental compliance mandates; new transmission lines needed to serve intermittent renewable power sources located far from load, reduce basis differentials within regional transmission organizations (RTO), or improve system reliability; advanced metering; and self-building for renewables mandates. Fitch notes that for integrated utilities with responsibility for generation as well as power distribution, 2009 capital spending averaged approximately 2.7x depreciation of existing assets, while for restructured electric T&D utilities, capex averaged a more manageable 1.5x depreciation charges (see the "Capital Spending Relative to Depreciation Charges" table on page 6). Fitch notes that utilities have good track records for full and timely recovery of environmental spending and that recovery of the transmission investments is often supported by RTO orders to build and constructive Federal Energy Regulatory Commission (FERC) tariffs, which are both significant spending categories for 2010.

Fitch believes capital investments will remain elevated for several years. Global climate change and GHG legislation is going to present enormous challenges to the industry over the intermediate to longer term, as utilities consider their options to comply with anticipated reductions in emissions, such as carbon capture and sequestration, integrated gasification combined-cycle power generation (IGCC), up-rates of existing nuclear plants or new-build nuclear, or renewable energy resources (27 states, and counting, have enacted RPS standards). While the low gas price environment makes power generation with natural gas an easy choice for near-term capacity needs and to back up intermittent wind or solar power, utility managements and state regulators are leery of renewed gas price volatility if eventually the oversupply of natural gas should self-correct. Moreover, gas is not a carbon-free choice, and longer term carbon goals under a national energy bill would not be met if load growth is mainly met through gas-fired capacity additions. Uncertainty about what to build and when is exacerbated by unknown impacts of energy efficiency and electric car efforts, and when pressures on customer bills from carbon allowances will ramp up to a meaningful level. The rating impact of these longer-term developments will be case by case, based on legislative and regulatory integrated resource plans and cost recovery decisions. For example, Ohio passed a law requiring future costs of carbon laws to be passed through to customers in the fuel adjustment mechanism, an encouraging sign for the credit of integrated electric utilities in the state.

Natural Gas Distributors

2010 Outlook — Stable
Longer-Term Outlook — Stable

Fitch's 2010 outlook for local gas distribution companies (LDCs) remains stable with expectations for continued operating, regulatory, and financial stability within the space in the long term. Natural gas prices have moderated as the quantity of gas in storage has hit historic highs heading into the 2009–2010 winter heating season. This will mean lower rates for consumers, alleviating some concern regarding rising bad debt expense given high unemployment and weakness in the economy. Additionally, state regulatory relations continue to be constructive for gas LDCs; many LDCs continue to successfully pursue progressive rate design crafted to stabilize financial exposure to changes in volumes sold.

Overall, gas LDCs weathered last year's capital market turmoil maintaining liquidity and access to capital markets. Gas prices were well off their mid-2008 highs by the start of the 2008–2009 heating season, and LDCs had delayed building inventory. Also, Fitch's concerns about increased bad debt expense in 2009 did not meaningfully materialize. Sales growth for the sector slowed significantly as the recessionary economy and a weak housing market slowed customer growth across the board. Continued weakness in the housing sector will constrain demand throughout 2010. Sales volumes have also been affected by a significant decline in industrial demand, particularly in the U.S. Midwest.

Fitch expects that moderate economic growth should help return industrial demand to more normalized levels in the second half of 2010. As a result of slower growth and slackened demand, LDC capital expenditures are expected to be focused on system maintenance rather than expansion and should remain fairly low (averaging approximately 1.5x depreciation charges), so there is not a need for significant external funding. The relatively low capital spending, coupled with lower rates charged to consumers via purchased gas cost adjustment mechanisms, will reduce the chance for any potential rate shock to customers and limit LDC exposure to adverse regulatory developments. Additionally, competitive energy sources, including fuel oil and propane, are correlated to crude oil prices and thus remain priced well above natural gas, limiting the potential for fuel-switching during 2010.

Conservation and the impact of weather on usage remain industry-wide concerns for natural gas LDCs, many of which have pursued rate designs in their regulatory jurisdictions intended to help address usage volatility. Currently, 18 states have approved the implementation of 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 revenues 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. 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.

Competitive Generation Companies

2010 Outlook — Negative
Longer-Term Outlook — Stable

Fitch's 2010 outlook for competitive generation companies is negative, as continued demand and price weakness will weigh on cash flow and credit metrics. Fitch typically views the competitive generators in two distinct subgroups: affiliated generators, which are subsidiaries of large utility holding companies or financial institutions and typically have investment-grade IDRs; and independent generators, which are standalone companies that typically have speculative-grade IDRs. Fitch's 2010 outlook is negative for both subgroups. Fitch expects that continued power price weakness, slack demand, and uncertainty surrounding carbon legislation will all weigh on the credit outlook for the competitive generating space throughout 2010. Fitch believes that earnings and cash flow, while likely improved over 2009 results, will continue to be muted, barring any significant recovery in commodity prices or industrial demand.

Last year proved to be a challenging environment for competitive generators across the spectrum. Lower demand and wholesale power prices pressured earnings and cash flow, particularly for some of the more highly levered independent generators, who in some cases were forced to sell assets, pay down some debt, and amend credit facility covenants. Dynegy Inc., for example, amended the covenants under it secured credit agreement and announced an agreement with LS Power to sell assets in exchange for cash and LS Power's class B units in Dynegy. These moves precipitated a negative rating action by Fitch in August when the transaction was announced. Negative rating and Outlook actions, in fact, were prevalent for many of the independent generators and affiliated generators under Fitch coverage, with a downgrade to Dynegy Inc. (DYN; IDR: 'B–'/Negative Outlook) and Outlook changes to Ameren Energy Generating Co. (IDR: 'BBB+'/Negative Outlook), Brookfield Renewable Power (BRPI; IDR 'BBB–'/Negative Outlook), Edison Mission Energy (EME; IDR: 'BB–'/Rating Watch Negative), Midwest Generation (IDR: 'BB'/Rating Watch Negative), RRI Energy (RRI; IDR 'B'/Negative Outlook) and Texas Competitive Electric Holdings (TCEH; IDR: 'B'/Negative Outlook).

Despite the discouraging fundamentals for this business segment, Fitch believes that the competitive generators have taken steps that will tend to mitigate further downside should wholesale power prices continue to languish through the year. The independent generators, in particular, have focused on cutting operating costs and hedging or contracting significant amounts of their expected generation for 2010 and 2011, actions that some of the companies had not previously taken in a more robust wholesale power pricing environment. Liquidity across the space remains adequate with most companies possessing sizable cash balances and revolver availability. Fitch also notes that despite declines in value from the peak in early 2009, enterprise valuations for most power generators are strong relative to outstanding indebtedness, which would lead to strong recoveries for secured debt for all but the most highly leveraged competitive generator issuers in a case of default.

Capital spending will remain muted as generators continue to take a conservative approach to growth spending, and environmental spending is delayed given the uncertainty surrounding carbon legislation and absent new mercury and sulfur dioxide rules. Notable exceptions include NRG, which continues to pursue its Repowering NRG capex program and has recently been an active investor in renewable resources; TCEH, which is in the process of completing the third of three large baseload power plants; and Exelon Generation Co., which is pursuing a large-scale nuclear up-rate program. Additionally, Fitch sees the potential for opportunistic asset sales and acquisitions, as more highly leveraged generators look to shore up balance sheets or more stable names look to grow and diversify their portfolios. With equity prices not reflecting the value of underlying assets, Fitch continues to believe there is a compelling argument for consolidation and acquisition within the space.

Longer term, looming carbon legislation remains a key operating and credit issue for the competitive generating space. The financial impact could be significant depending on the individual company's generation portfolio, as well as the specific form and cost assigned to emissions under proposed legislation and the direction of commodity prices. While the impacts of carbon legislation will vary for individual companies and in different power regions, it is reasonable to assume that less-efficient coal-fired generation will begin to be displaced first by gas-fired generation and, in the longer term by renewable projects, new nuclear, and potentially by carbon capture and sequestration clean coal technology (should that technology prove to be economically viable). Emission-free competitive generators with low variable-costs will be the biggest beneficiaries of carbon legislation. More-efficient natural gas-fired competitive generators are likely to see their generation dispatched more frequently as well.

Longer-term concerns include debt, credit facility, and term loan B maturities in the 2013–2016 timeframe; the roll off of current hedges; and the ability of competitive generators to recontract expected generation at levels that would support ratings. Debt maturities in 2010 are manageable, as most issuers do not face any significant refinancing. Additionally, with capital markets returning to a more normal pattern, access to capital should be open. However, particularly for the speculative-grade independent generators, capital will likely be significantly more expensive than prior to the financial crisis, reflecting changes in the bank market conditions, higher financing costs and weak equity valuations.

Public Power Utilities

2010 Outlook — Stable
Longer-Term Outlook — Stable to Negative

Fitch's Public Power and Electric Cooperative 2010 Outlook — Stable

Fitch's 2010 outlook for the public power and electric cooperative sectors continues to be stable despite the pressures that correspond with the national economic recession. After a rocky first half of 2009, capital market access has stabilized. However, there appears to be a lagging ripple-effect from the economic downturn that is working its way through local governments and creating downward rate pressure on public power utility systems that will persist well into 2010. Other credit pressures on the sector include: declining energy consumption related to the economic downturn, the need for rate increases in a difficult economic climate, limited/costly access to external liquidity, and state specific mandates — with the potential for federal mandates in 2010–2011 — regarding renewable energy sources and GHG emissions.

These pressures coincide with declines in natural gas and purchased power prices that have reduced the expenditure levels and provided some relief to many retail utilities. However, a softening of power market prices has resulted in lower-than-budgeted revenues from surplus power sales for several utilities. Growth levels have favorably slowed to more manageable levels in certain regions, providing an opportunity to adjust and re-evaluate system capital needs. While these current trends have not resulted in significant changes to the credit quality of the overall public power and electric cooperative sectors, Fitch intends to monitor variations specific to regions. Fitch notes that events in the next five to 10 years primarily related to expected environmental legislation could increase the cost structures of many electric utilities and potentially place pressure on credit ratings. Decisions regarding timely rate recovery of increased costs and the subsequent change in a utility's competitive position within its regional market will be key credit drivers. Fitch believes that the public power business model will continue to allow these utilities to perform well in 2010 and provide investors with a generally stable credit sector. Fitch's outlook for the sectors over the long term remains stable yet recognizes that increasing negative pressures are affecting the industry, primarily due to environmental mandates related to increased renewable energy resource requirements and GHG emissions restrictions. The possibility of carbon legislation being enacted looms over the public power industry and the specter of the proposed legislation is already impacting decisions on whether to build additional fossil-fuel baseload generation.

Short-Term Public Power Outlook

While there have been noticeable downward trends in financial metrics such as debt service coverage, cash-on-hand, and operating margins for both wholesale and retail public power systems, overall the sectors continue to benefit from solid credit fundamentals, including: essentiality of electric service, local control over rate-setting without state commission oversight, a cost advantage compared to neighboring investor-owned utilities, and benefits associated with a predominantly residential and commercial customer bases. Fitch expects that the average ratings for wholesale and retail utility systems, including electric cooperatives, will continue to be 'A' and 'A+', respectively. Fitch has noted in certain regions an increase in efforts by local governments to slow electric rate increases and boost transfers from the utility system to replace lower tax revenues and to fund the growing local government pension obligations. If unchecked, this trend could result in public power utilities with reduced liquidity and credit protection.

While varying in degree from region to region, overall the economic downturn and financial market disruptions have not yet resulted in material credit pressure on public power utilities. Public power and electric cooperatives have continued to have access to the capital markets, although borrowing costs have been higher than budgeted. Construction costs have declined and, in some cases, capital spending has been delayed. Generation investment is continuing, albeit at a slower pace, both through direct ownership and long-term bilateral contracts. Supply-related investments have been designed not only to meet load growth but increasingly to comply with local and state renewable resource requirements. Many utilities continue to realign their debt structure by reducing outstanding variable-rate exposure, given the disruptions in that market and the contraction/costliness in available liquidity facilities.

The economic contraction in many markets resulted in slower growth levels and consumption declines. Collection delinquencies and turn-off actions have increased only slightly despite the negative economic conditions, rising unemployment levels, and home foreclosures. Public power and electric cooperative utilities that are commodity purchasers have benefited from the recent decline in natural gas and wholesale power prices. However, several utilities that typically sell excess power into these markets have experienced lower-than-budgeted revenues from surplus sales, but many have maintained their financial margins through the use of conservative forecasting and budgeting practices, given the volatility of these revenue sources.

Long-Term Public Power Outlook

Fitch's long-term outlook for the sectors is stable but recognizes increasing negative credit pressures. Approval of national environmental mandates is still pending; however many utilities already face pressure from state or locally established renewable portfolio standards and must assess how to meet long-term load growth within an evolving environmental and generally more restrictive and costly regulatory framework. The growing pressure to enact carbon emissions restrictions to combat global climate change is expected to result in the enactment of national carbon legislation in the near future, but the structure, timing, and implementation schedule is still uncertain. Utilities, however, are already making decisions based on the anticipated legislation. Several large, baseload coal-fired power plants have been cancelled, and some of this planned future capacity is being replaced by natural gas and renewable generation. To the extent public power utilities rely mainly on natural gas-fired resources going forward, Fitch believes there could be a renewed risk of over-reliance on natural gas and the associated volatile fuel price exposure.

While Fitch believes that the public power and electric cooperative business models will continue to allow these utilities to perform well and prove to be stable credit sectors, increasingly negative market and industry factors could adversely impact some regions more than others. The utilities with greater credit exposure are those that have large capital improvement needs, relatively high leverage, below-average financial and rate flexibility, and a heavy reliance on fossil fuel generation. Conversely, systems that show stable to improving financial metrics, have limited new capital needs, and have a greener generation portfolio are expected to maintain Stable Outlooks and in some cases realize improved credit profiles.

Pipeline and Midstream Sector

Companies in the Pipeline/Midstream segment in 2009 faced the following pressing concerns: adequacy of liquidity, access to capital markets, the oncoming recession and its effects on demand for energy products, ability to defer capital spending, and commodity price trends. In response to these difficult operating conditions, companies overwhelming "played defense" and adopted cautious financial practices. In the face of a weakening economy and constrained capital markets, companies issued high-cost debt and equity to shore up their liquidity positions. Discretionary spending was cut to sustainable levels. Many MLPs adopted more conservative distribution practices to increase cash retention.

Entering 2010, business fundamentals are better than they were six or 12 months ago, but many challenges remain. Growth has slowed. Several large pipeline projects, burdened by increased construction and capital costs, will generate lower-than-expected, single-digit returns. The economy remains fragile. Given this backdrop, Fitch expects companies to stay the course by avoiding excess leverage and maintaining disciplined operating and growth strategies.

Natural Gas Pipelines

2010 Outlook — Stable
Longer-Term Outlook— Stable

Fitch foresees stable short-term and longer-term outlooks for interstate and intrastate natural gas pipelines. However, credit measures for companies funding large expansion projects will likely remain under pressure through 2010.

During 2008, completions of new natural gas pipelines and expansions of existing pipelines in the U.S represented the greatest amount of pipeline construction in more than 10 years. The added capacity for each of the top 15 projects exceeded 1 billion cubic feet per day (Bcf/d). The U.S. Energy Information Administration (EIA) reports that the number of proposed projects suggests construction activity will remain strong through 2011, with 2009 potentially showing the second-highest level of capacity additions in the decade. More than 10,200 miles of potential new gas pipelines are scheduled to be added in 2009–2011, but a portion of these projects will likely be delayed or canceled.

Even with cuts in discretionary spending by sponsor companies, weak commodity prices, and a slowly recovering economy, there is still a demand for new pipeline infrastructure to access unconventional resources, particularly natural gas from shale formations. Additionally, the costs of steel pipe, equipment, labor, and financing have declined from 2008–2009 highs, which will help companies attain adequate returns on their investments.

New North American Pipeline Capacity

	Proposed for 2010			Proposed for 2011		
	Added Capacity (MMcf/d)	Estimated Cost ($ Mil.)	Miles	Added Capacity (MMcf/d)	Estimated Cost ($ Mil.)	Miles
Central	3,655	1,820	871	1,528	491	290
Midwest	0	0	0	2,067	1,416	254
Northeast	2,491	1,276	249	4,318	2,465	599
Southeast	9,911	2,006	601	9,364	3,748	1,000
Southwest	6,283	577	293	13,915	2,162	688
Western	345	107	27	5,276	5,377	1,686
Mexico/Canada	1,920	N.A.	29	980	49	41
Total	**24,605**	**5,786**	**2,070**	**37,448**	**15,707**	**4,528**

N.A. – Not available.
Source: Energy Information Administration.

Products Pipelines

2010 Outlook — Stable
Longer Term — Stable

The pace of the economic recovery will affect demand for oil products and transportation volume, affecting crude oil and refined products pipelines. However, following reduced throughput in 2009, Fitch expects product demand to stabilize.

Midstream Services

2010 Outlook — Stable
Longer Term — Stable

For natural gas gatherers, both the short-term and long-term outlooks are stable, while for gas processors the short-term outlook is negative. After several years of high processing margins, in late 2008 natural gas liquids (NGL) unit margins dropped. While margins have recovered back to more historical norms, future commodity margins are uncertain. Financial performance for some companies will also be affected by hedging practices and their economic sensitivity to natural gas prices. Fitch expects natural gas to trade in a relatively low price range, which is unfavorable to most processors. Moreover, in some production basins, price-induced drilling reductions are expected to lower gathering volumes until demand recovers, an adverse trend for both processors and gatherers.

Retail Propane

2010 Outlook — Negative
Longer-Term Outlook— Negative

Fitch maintains a modestly negative short- and long-term outlook for the retail propane sector. Given propane's strong correlation to crude oil prices, Fitch remains concerned that retail propane prices could spike, particularly with a weak dollar, and margins could contract from current levels. Additionally, continued weakness in housing starts and a warmer winter could weigh on volumes sold. If sales volumes show a greater post-recession recovery and product margins hold up, the credit outlook would move toward stable.

For more information on the credit outlook for these businesses, please refer to Fitch's report, "Pipeline/Midstream/MLP 2010 Outlook," published on Dec. 3, 2009.

Appendix: Ratings and Rating Outlooks by Segment

Utility Parent Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
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
AGL Resources, Inc.	A–	Stable	A–
DPL Inc.	A–	Stable	A–
KeySpan Corporation	A–	Stable	A–
Laclede Group, Inc.(The)	A–	Stable	**NR**
MDU Resources Group, Inc.	A–	Negative	A
National Fuel Gas Company	A–	Stable	A–
NSTAR	A–	Stable	A
Wisconsin Energy Corporation	A–	Negative	A–
Ameren Corporation	BBB+	Stable	BBB+
Consolidated Edison, Inc.	BBB+	Stable	BBB+
Dominion Resources, Inc.	BBB+	Stable	BBB+
Energy East Corporation	BBB+	Stable	**NR**
Exelon Corporation	BBB+	Stable	BBB+
MidAmerican Energy Holdings Co.	BBB+	Stable	BBB+
Public Service Enterprise Group Inc	BBB+	Stable	BBB+
SCANA Corporation	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
DTE Energy Company	BBB	Negative	BBB
FirstEnergy Corp.	BBB	Stable	BBB
IDACORP, Inc.	BBB	Negative	**NR**
Northeast Utilities	BBB	Stable	BBB
PEPCO Holdings	BBB	Negative	BBB
PPL Corporation	BBB	Stable	BBB
Progress Energy, Inc	BBB	Stable	BBB
Below Segment Median Rating			
Allegheny Energy, Inc.	BBB–	Stable	BBB–
Avista Corporation	BBB–	Stable	BBB
CenterPoint Energy Inc.	BBB–	Stable	BBB–
CILCORP, Inc.	BBB–	Stable	BBB–
Constellation Energy Group, Inc.	BBB–	Stable	BBB–
Edison International	BBB–	Stable	**NR**
IPALCO Enterprises, Inc.	BBB–	Stable	**BBB–**
NiSource Inc.	BBB–	Stable	BBB
Otter Tail Corporation	BBB–	Stable	BBB–
Pinnacle West Capital Corporation	BBB–	Negative	BBB–
TECO Energy, Inc.	BBB–	Stable	BBB–
CMS Energy Corporation	BB+	Stable	BB+
PSEG Energy Holdings, Inc.	BB+	Stable	BB
PNM Resources	BB	Stable	BB
NV Energy Inc.	BB–	Positive	BB–
Energy Future Holdings Corp.	B	Negative	B
Energy Future Intermediate Holding Company LLC	B	Negative	**B+**

NR – Not rated. Note: Bold indicates senior secured.
Source: Fitch.

Investor-Owned Electric Utilities

Integrated Electric Utilities

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+
Dayton Power & Light Company	A	Stable	**AA–**
Florida Power and Light	A	Stable	A+
Georgia Power Company	A	Negative	A+
Wisconsin Electric Power Company	A	Negative	A+
Carolina Power & Light Co.	A–	Stable	A
Florida Power Corp.	A–	Stable	A
Gulf Power Company	A–	Stable	A
MidAmerican Energy Company	A–	Stable	A
Northern States Power Company (MN)	A–	Stable	A
Northern States Power Company (WI)	A–	Stable	A
Pacific Gas and Electric Company	A–	Stable	A
Southern California Edison Company	A–	Stable	A
AEP Texas North Company	BBB+	Stable	A–
Columbus Southern Power Company	BBB+	Stable	A–
Public Service Company of Colorado	BBB+	Stable	A–
South Carolina Electric & Gas Co.	BBB+	Stable	A–
Union Electric Co.	BBB+	Stable	A–
Virginia Electric and Power	BBB+	Stable	A–
At Segment Median Rating			
AEP Texas Central Company	BBB	Negative	BBB+
Black Hills Power, Inc.	BBB	Stable	BBB+
Central Illinois Light Company	BBB	Stable	BBB+
Detroit Edison Company (DECo)	BBB	Stable	**A–**
Idaho Power Company	BBB	Negative	BBB+
Ohio Power Company	BBB	Stable	BBB+
Otter Tail Power	BBB	Stable	BBB+
PacifiCorp	BBB	Stable	BBB+
Public Service Company of New Hampshire	BBB	Stable	**BBB+**
Public Service Company of Oklahoma	BBB	Stable	BBB+
Southwestern Electric Power Company	BBB	Negative	BBB+
Southwestern Public Service Company	BBB	Stable	BBB+
Tampa Electric Company	BBB	Stable	BBB+
Below Segment Median Rating			
Appalachian Power Company	BBB–	Stable	BBB
Arizona Public Service Company	BBB–	Stable	BBB
Consumers Energy Company	BBB–	Stable	BBB
Empire District Electric Company	BBB–	Negative	BBB
Indiana Michigan Power Company	BBB–	Stable	BBB
Indianapolis Power & Light Company	BBB–	Stable	BBB
Kansas Gas and Electric Company	BBB–	Stable	**BBB+**
Kentucky Power Company	BBB–	Stable	BBB
Monongahela Power Company	BBB–	Stable	BBB–
Northern Indiana Public Service Co.	BBB–	Stable	BBB
Northwestern Corporation	BBB–	Stable	BBB
Westar Energy, Inc.	BBB–	Stable	BBB
Nevada Power Company d/b/a NV Energy	BB	Positive	BB
Public Service Company of New Mexico	BB	Stable	BB+
Sierra Pacific Power Company d/b/a NV Energy	BB	Positive	**BBB–**
Tucson Electric Power Company	BB	Positive	BB+

Note: Bold indicates senior secured. *Continued on next page*.
Source: Fitch.

FitchRatings
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Investor-Owned Electric Utilities (Continued)

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 Company	A+	Stable	AA–
American Transmission Company	A	Stable	A+
Central Hudson Gas & Electric Corp	A–	Stable	A
Orange and Rockland Utilities, Inc.	A–	Negative	A
Rockland Electric Co.	A–	Negative	**NR**
Consolidated Edison Co. of New York	BBB+	Stable	A–
Delmarva Power & Light	BBB+	Stable	A–
PECO Energy Company	BBB+	Stable	**A**
Potomac Electric Power Company	BBB+	Stable	A–
Public Service Electric and Gas Co.	BBB+	Stable	**A**
At Segment Median Rating			
Atlantic City Electric	BBB	Stable	BBB+
Baltimore Gas and 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+
Below Segment Median Rating			
Central Illinois Public Service Co.	BBB–	Stable	BBB
Illinois Power Company	BBB–	Stable	BBB
Metropolitan Edison Company	BBB–	Stable	BBB
Ohio Edison Company	BBB–	Stable	BBB
Oncor Electric Delivery Company	BBB–	Stable	BBB–
Pennsylvania Electric Company	BBB–	Stable	BBB
Pennsylvania Power Company	BBB–	Stable	BBB
Potomac Edison Company (The)	BBB–	Stable	**BBB+**
Rochester Gas and Electric Corp	BBB–	Stable	BBB
West Penn Power Company	BBB–	Stable	BBB–
Cleveland Electric Illuminating Co.	BB+	Stable	BBB–
Commonwealth Edison Company	BB+	Stable	BBB–
Texas New Mexico Power Company	BB+	Stable	BBB–
Toledo Edison Company	BB+	Stable	BBB–

NR – Not rated. Note: Bold indicates senior secured.
Source: Fitch.

Competitive Generation Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
AmerenEnergy Generating Company	BBB+	Negative	BBB+
Exelon Generation Company, LLC	BBB+	Stable	BBB+
PSEG Power, LLC	BBB+	Stable	BBB+
Southern Power Company	BBB+	Stable	BBB+
FirstEnergy Solutions Corp. (FES)	BBB	Stable	BBB
PPL Energy Supply	BBB	Stable	BBB+
Allegheny Energy Supply Company	BBB–	Stable	BBB–
Allegheny Generating Company	BBB–	Stable	BBB–
Brookfield Renewable Power, Inc.	BBB–	Negative	BBB
Midwest Generation, LLC	BB	RWN	**BBB–**
At Segment Median Rating			
Edison Mission Energy	BB–	RWN	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 Corporation	B+	Stable	**NR**
Mirant Mid-Atlantic, LLC	B+	Stable	BB+
Mirant North America, LLC	B+	Stable	BB–
NRG Energy, Inc.	B	RWE	B+
Reliant Energy Inc	B	Negative	B+
Texas Competitive Electric Holdings	B	Negative	B
Dynegy Holdings, Inc.	B–	Negative	B
Dynegy, Inc.	B–	Negative	**NR**

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

FitchRatings
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Pipeline and Midstream Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Northern Natural Gas Co.	A	Stable	A
Centennial Energy Holdings, Inc.	A–	Negative	A–
LOOP LLC	A–	Stable	A–
EQT Corporation	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
DCP Midstream LLC	BBB	Stable	BBB
Enogex Inc.	BBB	Stable	BBB
Kinder Morgan Energy Partners, L.P.	BBB	Stable	BBB
Northwest Pipeline Corporation	BBB	Stable	BBB
Rockies Express Pipeline LLC	BBB	Stable	BBB
Transcontinental Gas Pipe Line Corp	BBB	Stable	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, LLC.	BBB–	Stable	BBB–
NGPL PipeCo LLC	BBB–	Stable	BBB–
NPOP (Kaneb Pipe Line Operating Partnership, L.P.)	BBB–	Stable	BBB–
NuStar Logistics, L.P.	BBB–	Stable	BBB–
Panhandle Eastern Pipeline Co.	BBB–	Stable	BBB–
Southern Natural Gas Co.	BBB–	Stable	BBB–
Southern Union Company	BBB–	Stable	BBB–
Tennessee Gas Pipeline Co.	BBB–	Stable	BBB–
TEPPCO Partners L.P.	BBB–	Stable	BBB–
Williams Companies, Inc.	BBB–	Stable	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
Kinder Morgan 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	BB–

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 Company	A+	Stable	AA–
Washington Gas Light Company	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–	Negative	A
KeySpan Gas East Corporation	A–	Stable	A
Laclede Gas Company	A–	Stable	**A+**
NSTAR Gas	A–	Stable	**A**
UGI Utilities, Inc.	A–	Stable	A
Below Segment Median Rating			
Berkshire Gas Company	BBB+	Stable	A–
Central Maine Power Company	BBB+	Stable	A–
Connecticut Natural Gas	BBB+	Stable	A–
Public Service Company of North Carolina	BBB+	Stable	A–
Atmos Energy Corporation	BBB	Stable	BBB+
Southern Connecticut Gas	BBB	Negative	**A–**
Southwest Gas Corporation	BBB	Stable	BBB
Michigan Consolidated Gas Company	BBB–	Stable	**BBB+**
Mountaineer Gas Company	BB–	Stable	BB

Note: Bold indicates senior secured.
Source: Fitch.

FitchRatings
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Public Power Companies — Retail Segment

Company Name	Rating Outlook	Senior Unsecured Rating
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
Colorado Springs Utilities	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.)	Negative	AA–
Austin Combined Utility System (Texas)	Stable	AA–
Austin Energy (Texas)	Stable	AA–
Concord (N.C.) Utilities System	Stable	AA–
Hydro-Quebec	Stable	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–
Richmond (Va.)	Stable	AA–
Riverside Public Utilities (Calif.)	Stable	AA–
Rochester Public Utilities (Minn.)	Stable	AA–
Snohomish County Public Utility District No. 1 (Wash.)	Stable	AA–
Tallahassee (Fla.) — Energy System	Stable	AA–
At Median (A+)		
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+
Georgetown (Texas)	Stable	A+
Greer (S.C.) — Commission of Public Works	Stable	A+
Imperial Irrigation District (Calif.)	RWN	A+
Jacksonville Beach (Fla.) — Combined Utility System	Stable	A+
Kansas City (Kan.) — Board of Public Utilities	Stable	A+
Kerrville Public Utility Board (Texas)	Stable	A+
Lakeland Energy System (Fla.)	Stable	A+
Muscatine Power & Water (Iowa)	Stable	A+
Ocala (Fla.)	Stable	A+
Pedernales Electric Cooperative, Inc. (Texas)	Stable	A+
Redding (Calif.)	Stable	A+
Roseville Electric System (Calif.)	Stable	A+
Tacoma Power (Wash.)	Stable	A+
Turlock Irrigation District (Calif.)	Stable	A+
Below Median (A+)		
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
Granbury (TX)	Negative	A
Grays Harbor County Public Utility District No. 1 (Wash.)	Stable	A
Kissimmee Utility Authority (Fla.)	Stable	A
Modesto Irrigation District (Calif.)	Stable	A

RWN – Rating Watch Negative. *Continued on next page.*
Source: Fitch.

Public Power Companies — Retail Segment (Continued)

Company Name	Rating Outlook	Senior Unsecured Rating
Below Median (A+) (Continued)		
Overton Power District No. 5 (NV)	Stable	A
Paducah (Kent.)	Stable	A
Reedy Creek Improvement District (Fla.)	Stable	A
Sacramento Municipal Utility District (Calif.)	Stable	A
Silicon Valley Power (Calif.)	Stable	A
Vero Beach (Fla.)	Stable	A
Winter Park (Fla.)	Negative	A
Alameda Power & Telecom (Calif.)	Positive	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–
Klickitat County Public Utility District No. 1 (WA)	Stable	A–
Long Island Power Authority (N.Y.)	Negative	A–
Los Alamos County (N.M.) — Utility System	Stable	A–
Lubbock Power & Light (Texas)	Stable	A–
Pend Oreille County Public Utility District No. 1 (Wash.)	Stable	A–
Seguin (Texas)	Stable	A–
Leesburg (Fla.) — Electric System	Stable	BBB+
Lodi (Calif.) — Electric Utility	Positive	BBB+
Puerto Rico Electric Power Authority	Stable	BBB+
Virgin Islands Water & Power Authority	Negative	BBB
Vermont Electric Cooperative Inc.	Stable	BBB–
Guam Power Authority	Positive	BB+

Source: Fitch.

Public Power Companies — Wholesale Segment

Company Name	Rating Outlook	Senior Unsecured Rating
Above Median (A)		
Tennessee Valley Authority	Stable	AAA
Associated Electric Cooperative Inc. (MO)	Stable	AA
Energy Northwest (Wash) — Bonneville Power Agency	Positive	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–
Intermountain Power Agency (Utah)	Stable	AA–
Western Minnesota Municipal Power Agency	Stable	AA–
Arkansas Electric Cooperative Corp.	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+
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+
Buckeye Power, Inc (Ohio)	Stable	A+
At Median (A)		
American Municipal Power — Issuer Rating	Stable	A
American Municipal Power-Inc. — Joint Venture No. 5	Stable	A
American Municipal Power-Inc. — Prairie State Project	Stable	A
Berkshire Wind Power Cooperative Corporation (MA)	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
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
M-S-R Public Power Agency (Calif.)	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
Below Median (A)		
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 (MN)	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–
PowerSouth Energy Cooperative, Inc.	Stable	A–
South Texas Electric Cooperative	Stable	A–

Continued on next page.
Source: Fitch.

FitchRatings
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Public Power Companies — Wholesale Segment (Continued)

Company Name	Rating Outlook	Senior Unsecured Rating
Wholesale Segment — Below Median (A) (Continued)		
Western Farmers Electric Cooperative (Okla.)	Negative	A–
Central Valley Financing Authority (Calif.)	Stable	BBB+
North Carolina Eastern Municipal Power Agency	Positive	BBB+
Piedmont Municipal Power Agency (S.C.)	Stable	BBB+
Sacramento Cogeneration Authority (Calif.) — P&G Project	Stable	BBB+
Sacramento Power Authority (Calif.) — Campbell Project	Stable	BBB+
Sacramento Municipal Utility District Financing Authority (Calif.) — Cosumnes Project	Stable	BBB
Big Rivers Electric Corporation (Kent.)	Stable	BBB–
Sam Rayburn Municipal Power Agency (Texas)	Stable	BBB–

Source: Fitch.

November 9, 2010

WELLS FARGO SECURITIES

Equity Research

Ameren Corp.

AEE: Adjusting EPS Outlook; Reiterate Market Perform

Market Perform

Sector: IPP/Regulated Electric Utilities
Market Weight

- **Summary.** Based on 2010 YTD results, revised rate relief assumptions, updated hedging disclosures and current forward power prices, our revised our '10-14 EPS estimates are $2.70, $2.15, $2.05, $1.70 and $1.95 vs. $2.65. $2.10, $2.15, $1.65 and $1.95, previously. We reiterate our Market Perform rating and increase our valuation range to $28-29 from $26-27 reflecting a higher valuation for the Regulated Utility business.
- **2010 Outlook.** Following a strong 3Q, AEE raised the lower end of its 2010 core earnings guidance range by $0.10 resulting in a revised range of $2.60-2.80, including $2.25-2.35 from the Regulated Utilities (vs. $2.15-2.30 previously) and $0.35-0.45 from Merchant Generation (vs. $0.35-0.50 previously). Excluding the return of Noranda Aluminum's smelter plant, 3Q industrial sales were +10% and residential and commercial sales were +28% and +11%, respectively. We are increasing our 10E EPS to $2.70 from $2.65.
- **EPS Outlook.** Our revised 11E-14E EPS are $2.15, $2.05, $1.70 and $1.95 versus $2.10, $2.15, $1.65 and $1.95, previously. The changes reflect AEE's updated hedging disclosures, adjustments to our power price assumptions and revised rate relief assumptions related to the IL rehearing order and the Missouri electric rate case filing. Our estimates assume the Merchant Generation business loses $0.22/share in '12 and $0.61/share in '13, which embed open ATC prices of roughly $35.00/MWh and $37.50/MWh, respectively, including a small adder for various ancillary products. See Figure 1 for key merchant assumptions.
- **Merchant Impairment.** In 3Q, AEE took a $485mm non-cash goodwill and asset impairment charge related to the company's merchant assets. The out-of-cycle impairment was triggered by Blackstone's proposed acquisition of Dynegy, which resulted in a lower industry market multiple, potentially more stringent environmental rules related to the EPA's July 2010 Clean Air Transport Rule (CATR) proposal and a continued decline in power prices. The impairment highlights the challenging environment for AEE's Merchant Generation business, in our view.
- **Reiterate Market Perform.** We reiterate our Market Perform rating and raise our valuation range to $28-29 from $26-27 largely based on a higher Regulated Electric median P/E multiple. We remain concerned about the long-term outlook for the Merchant Generation business.

Earnings Estimates Revised Up

EPS	2009A	2010E Curr.	2010E Prior	2011E Curr.	2011E Prior
Q1 (Mar.)	$0.54	$0.40 A	NC	NE	
Q2 (June)	0.75	0.73 A	NC	NE	
Q3 (Sep.)	1.16	**1.40 A**	**1.22**	NE	
Q4 (Dec.)	0.37	**0.17**	**0.30**	NE	
FY	$2.79	**$2.70**	**2.65**	**$2.15**	**2.10**
CY	$2.79	$2.70		$2.15	
FY P/E	10.6x	10.9x		13.7x	
Rev.(MM)	$7,090	$8,262		$8,210	

Source: Company Data, Wells Fargo Securities, LLC estimates, and Reuters
NA = Not Available, NC = No Change, NE = No Estimate, NM = Not Meaningful
V = Volatile, = Company is on the Priority Stock List

Ticker	AEE
Price (11/09/2010)	$29.54
52-Week Range:	$23-30
Shares Outstanding: (MM)	239.2
Market Cap.: (MM)	$7,066.0
S&P 500:	1,213.40
Avg. Daily Vol.:	1,835,640
Dividend/Yield:	$1.54/5.2%
LT Debt: (MM)	$6,859.0
LT Debt/Total Cap.:	45.0%
ROE:	7.0%
3-5 Yr. Est. Growth Rate:	(7.0)%
CY 2010 Est. P/E-to-Growth:	NM
Last Reporting Date:	10/29/2010 Before Open

Source: Company Data, Wells Fargo Securities, LLC estimates, and Reuters

Valuation Range: $28.00 to $29.00 from $26.00 to $27.00
Our sum-of-the-parts valuation analysis includes $29-30 for Regulated Operations (apply a 13X multiple to Regulated 2012E EPS of $2.27) and $0-(1) for Merchant Generation, resulting in our $28-29 valuation range. Risks to our valuation include unfavorable regulatory outcomes, a further deterioration in power prices and a material rise in interest rates.

Investment Thesis:
Despite a favorable outlook for the regulated business and an attractive dividend yield, we rate the shares Market Perform based on the current poor outlook for the merchant generation business and valuation considerations.

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Please see page 5 for rating definitions, important disclosures and required analyst certifications

Company Description:

(St. Louis, MO) Ameren's primary businesses are regulated electric and natural gas utility services and merchant generation. The company's four regulated subsidiaries serve 2.4 million electric customers and one million natural gas customers in Missouri and Illinois. AEE's regulated rate base by jurisdiction is as follows: Missouri-60%, Illinois-35% and Federal Energy Regulatory Commission (FERC)-5%. The regulated utilities include AmerenUE (Missouri) and the Ameren Illinois Utilities (AIU) comprised of AmerenCILCO (CILCO), AmerenCIPS (CIPS) and AmerenIP (IP). Merchant Generation owns approximately 6,400 MW of capacity in Illinois, including over 4,600 MW of coal-fired generation.

Figure 1: Key Assumptions Underlying Merchant Generation Earnings Outlook, 2010E-14E

	2010E	2011E	2012E	2013E	2014E
Key Generation Assumptions					
Capacity (MW)	6,421	6,421	6,421	6,421	6,421
Plant Output (mm MWhs)	30,508	30,508	30,508	30,508	30,508
Hedged Output (mm MWhs)	29,898	24,407	15,864	3,051	0
Avg Realized Price ($/MWh)*	$46.50	$46.00	$51.00	$39.30	$42.11
Revenues (mil.)	$1,390	$1,123	$809	$120	$0
Unhedged Output (mm MWhs)	610	6,102	14,644	27,458	30,508
Avg Realized Price ($/MWh)	$30.98	$32.28	$34.82	$37.43	$40.11
Revenues (mil.)	$19	$197	$510	$1,028	$1,224
Non Full-Requirements Capacity Revenues (mil.)	$63	$49	$39	$88	$88
Other Revenues (mil.)	$15	$15	$15	$15	$15
Total AER Revenues	**$1,488**	**$1,384**	**$1,373**	**$1,250**	**$1,327**
Key Coal Fuel Cost Assumptions					
Tons (mil.)	14	14	14	14	14
$/ton	$48.36	$54.09	$56.34	$57.07	$57.31
$/MWh	$22.50	$25.16	$26.20	$26.54	$26.66
Guidance	*$22.50*	*$25.00*	*$26.00*	*N/A*	*N/A*
Fuel Costs	$686	$768	$799	$810	$813
*% Coal Hedged***	*95%*	*66%*	*40%*	*N/A*	*N/A*
*% Transportation Hedged***	*100%*	*95%*	*90%*	*N/A*	*N/A*
Gross Margin & EBITDA (mil.)					
Total Revenues	$1,488	$1,384	$1,373	$1,250	$1,327
Fuel Costs	$686	$768	$799	$810	$813
Gross Margin	**$801**	**$616**	**$573**	**$441**	**$513**
$/MWh	*$26.26*	*$20.20*	*$18.79*	*$14.44*	*$16.82*
Operating & Maintenance Expense	$281	$289	$298	$307	$316
Other Taxes	$42	$43	$44	$45	$46
EBITDA	**$478**	**$284**	**$231**	**$89**	**$151**

*2010-2012 hedged percentage & average hedged power price are per company guidance.
2013 & 2014 hedged percentage & average hedged power price are Wells Fargo Securities, LLC estimates.
**Percentages Based on AEE guidance for hedged coal and transportation (mm MWh) divided by an estimated 30 mm MWh annual output.

Source: Wells Fargo Securities, LLC Estimates and AEE guidance

Earnings Model (in millions, except per share data)	2007	2008	2009	2010E	2011E	2012E	2013E	2014E
Revenues	**$7,562**	**$7,839**	**$7,090**	**$8,262**	**$8,210**	**$8,388**	**$8,415**	**$8,658**
Operating Expenses								
Energy Costs	$3,454	$3,542	$2,799	$3,800	$3,860	$3,928	$3,975	$4,016
Operations & Maintenance	1,687	1,857	1,738	1,825	1,870	1,911	1,953	1,996
Depreciaton & Amortization	681	685	725	752	786	812	839	867
Other Taxes	381	393	412	423	432	441	450	459
Total Expenses	**$6,203**	**$6,477**	**$5,674**	**$6,801**	**$6,947**	**$7,091**	**$7,217**	**$7,338**
Operating Income	**$1,359**	**$1,362**	**$1,416**	**$1,461**	**$1,263**	**$1,297**	**$1,199**	**$1,321**
EBITDA	**$2,040**	**$2,047**	**$2,141**	**$2,213**	**$2,049**	**$2,109**	**$2,037**	**$2,187**
Other Income	50	49	48	70	66	41	31	25
Interest Expense	423	440	508	522	517	540	553	542
Income Taxes	330	327	332	351	278	282	237	282
Income before Minority Interest & Pfd. Div.	**$656**	**$644**	**$624**	**$658**	**$534**	**$515**	**$440**	**$521**
Minority Interest & Preferred Dividends	38	39	12	12	12	12	12	12
Net Income	**$618**	**$605**	**$612**	**$646**	**$523**	**$504**	**$428**	**$509**
Average Diluted Shares Outstanding	207	210	220	239	243	246	252	261
EPS	$2.98	$2.88	$2.78	$2.70	$2.15	$2.05	$1.70	$1.95
Non-Recurring Items	0.36	0.07	0.01	0.00	0.00	0.00	0.00	0.00
Operating EPS*	**$3.34**	**$2.95**	**$2.79**	**$2.70**	**$2.15**	**$2.05**	**$1.70**	**$1.95**

Supplemental Information	2007	2008	2009	2010E	2011E	2012E	2013E	2014E
EPS By Segment								
Regulated Utilities								
Missouri				$1.69	$1.69	$1.65	$1.65	$1.69
Illinois				0.58	0.54	0.62	0.65	0.65
Ameren Transmission Company				0.00	0.00	0.00	0.01	0.03
Total Regulated				2.27	2.24	2.27	2.31	2.37
Total Non-Regulated and Parent				0.43	(0.08)	(0.22)	(0.61)	(0.42)
Total				**$2.70**	**$2.15**	**$2.05**	**$1.70**	**$1.95**
Dividend Information								
Dividend/Share Year-End Rate	$2.54	$2.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54
Dividends Paid Per Share	2.54	2.54	1.54	1.54	1.54	1.54	1.54	1.54
Payout Ratio	**76%**	**86%**	**55%**	**57%**	**71%**	**75%**	**91%**	**79%**
Statistics								
Book Value Per Share - Year End	$32.41	$32.80	$33.08	$34.11	$34.61	$35.02	$34.97	$35.21
Average Book Value Per Share	16.21	32.61	32.94	33.60	34.36	34.82	35.00	35.09
ROE	**21%**	**9%**	**8%**	**8%**	**6%**	**6%**	**5%**	**6%**
EBITDA Per Share	9.84	9.74	9.71	9.25	8.44	8.57	8.08	8.37
Cash Flow Per Share	5.34	7.25	8.97	7.79	5.66	5.61	5.28	5.51
Free Cash Flow Per Share	(3.86)	(4.31)	(0.29)	1.40	(1.17)	(1.27)	(1.92)	(1.37)

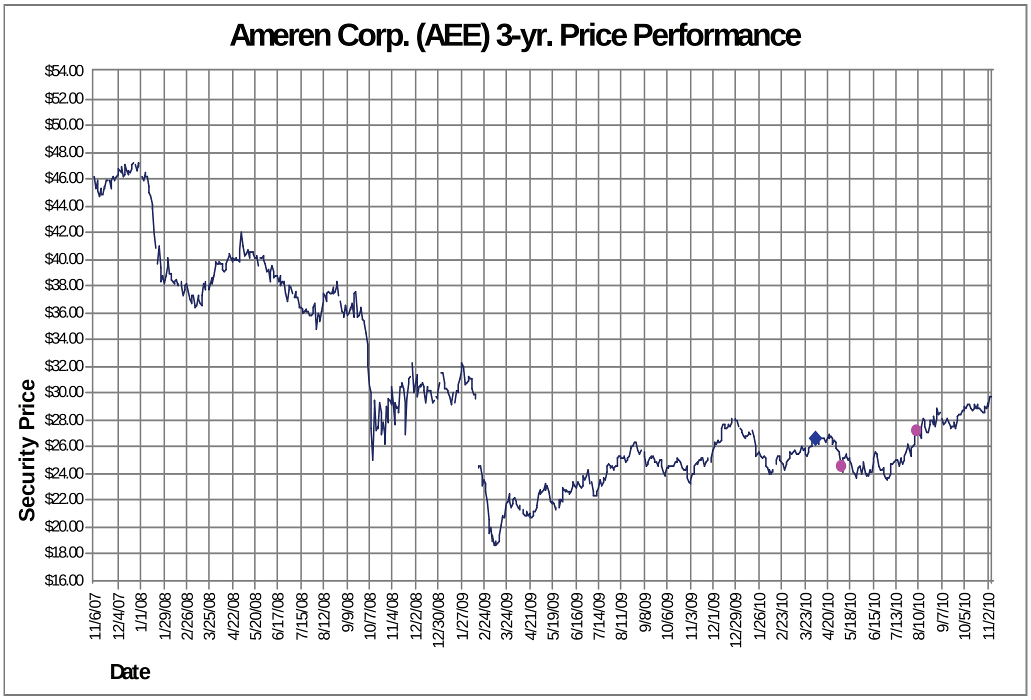
*Operating EPS exclude non-recurring items.
Source: Wells Fargo Securities, LLC estimates and company filings

Cash Flow Model (in millions)	2007	2008	2009	2010E	2011E	2012E	2013E	2014E
Operating Cash Flow								
Net Income	$656	$644	$624	$658	$534	$515	$440	$521
Depreciation & Amortization	(9)	187	427	400	0	0	0	0
Other	461	693	926	805	839	865	892	920
Net Operating Cash Flow	**$1,108**	**$1,524**	**$1,977**	**$1,863**	**$1,373**	**$1,380**	**$1,331**	**$1,441**
Investing Cash Flow								
Capital Expenditures	(1,381)	(1,896)	(1,704)	(1,160)	(1,283)	(1,315)	(1,427)	(1,395)
Other	(87)	(201)	(85)	(75)	(80)	(80)	(80)	(80)
Net Investing Cash Flow	**($1,468)**	**($2,097)**	**($1,789)**	**($1,235)**	**($1,363)**	**($1,395)**	**($1,507)**	**($1,475)**
Financing Cash Flow								
Net Change in ST Debt	860	(298)	(324)	0	0	0	0	0
Capital Issuance Costs	(4)	(12)	(65)	0	0	0	0	0
Issuance of LT Debt	674	1,879	1,021	0	400	312	547	323
Dividends Paid to Noncontrolling Interest Holders	(32)	(40)	(21)	(12)	(12)	(12)	(12)	(12)
Redemption/Purchase of LT Debt	(488)	(842)	(631)	(204)	(154)	(178)	(354)	(533)
Redemption of Preferred Securities	(1)	(16)	0	0	0	0	0	0
Issuance of Common Stock	91	154	634	90	90	90	250	300
Dividends on Common Stock	(527)	(534)	(338)	(368)	(374)	(379)	(388)	(402)
Generator Advances Received for Construction	5	19	66	0	0	0	0	0
Net Financing Cash Flow	**$578**	**$310**	**$342**	**($494)**	**($49)**	**($167)**	**$43**	**($324)**
Net Change in Cash	$218	($263)	$530	$134	($40)	($181)	($132)	($358)
Cash at Beginning of Period	137	355	92	622	756	717	536	403
Cash at End of Period	**$355**	**$92**	**$622**	**$756**	**$717**	**$536**	**$403**	**$45**

Capital Structure	2007	2008	2009	2010E	2011E	2012E	2013E	2014E
Common Equity	$6,752	$6,963	$7,853	$8,221	$8,460	$8,675	$8,965	$9,372
LT Debt	5,689	6,554	7,113	7,113	7,359	7,493	7,686	7,476
ST Debt	1,695	1,554	1,054	850	850	850	850	850
Preferred Stock	211	216	207	207	207	207	207	207
Total Capital	**$14,347**	**$15,287**	**$16,227**	**$16,391**	**$16,876**	**$17,225**	**$17,708**	**$17,905**
Common Equity	47%	46%	48%	50%	50%	50%	51%	52%
LT Debt	40%	43%	44%	43%	44%	44%	43%	42%
ST Debt	12%	10%	6%	5%	5%	5%	5%	5%
Preferred	1%	1%	1%	1%	1%	1%	1%	1%

Source: Wells Fargo Securities, LLC estimates and company filings

Required Disclosures



	Date	Publication Price ($)	Rating Code	Val. Rng. Low	Val. Rng. High	Close Price ($)
◆	4/6/2010	26.48	2	27.00	28.00	26.65
●	5/6/2010	25.39	2	25.00	26.00	24.66
●	8/6/2010	27.04	2	26.00	27.00	27.20

Source: Wells Fargo Securities, LLC estimates and Reuters data

Symbol Key

▼ Rating Downgrade
▲ Rating Upgrade
● Valuation Range Change
◆ Initiation, Resumption, Drop or Suspend
■ Analyst Change
□ Split Adjustment

Rating Code Key

1 Outperform/Buy
2 Market Perform/Hold
3 Underperform/Sell
SR Suspended
NR Not Rated
NE No Estimate

Additional Information Available Upon Request

I certify that:
1) All views expressed in this research report accurately reflect my personal views about any and all of the subject securities or issuers discussed; and
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AEE: Risks to our valuation include unfavorable regulatory outcomes, a further deterioration in power prices and a material rise in interest rates.

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M=Market Weight: Industry expected to perform in-line with the relevant broad market benchmark over the next 12 months.
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As of: November 9, 2010

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December 29, 2010

Ameren Illinois Co.

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Ameren Illinois Co.

Major Rating Factors

Corporate Credit Rating
BBB-/Stable/NR

Strengths:
- A fully regulated electric and gas company;
- Lower risk transmission and distribution businesses; and
- Near-term improved financial measures.

Weaknesses:
- Affiliation with the higher-risk operations and less dependable cash flows from Ameren's merchant generation business; and
- Rising regulatory risk in Illinois.

Rationale

The ratings on Ameren Illinois reflect Ameren Corp.'s (Ameren) consolidated credit profile. The ratings also reflect Ameren Illinois' excellent business risk profile and Ameren's consolidated significant financial risk profile. Ameren's subsidiaries include rate regulated utilities Ameren Illinois and Ameren Missouri, and merchant energy company AmerenEnergy Generating Co. (GenCo.) As of Sept. 30, 2010, Ameren had about $7.7 billion of total debt outstanding. Based on the combination of future earnings, cash flow, capital expenditures, and credit risk exposure, we view Ameren as about 75% regulated and 25% merchant generation.

Ameren Illinois' excellent business risk profile reflects its lower-risk pure transmission and distribution (T&D) operations. The company serves about 1.2 million electric customers and 813,000 gas customers in central and southern Illinois, whose rates are regulated by the Illinois Commerce Commission (ICC). Additionally, the company's electric transmission lines, which constitutes about 13% of the company's total rate base and is regulated by the Federal Energy Regulatory Commission, provides some added diversification. Overall, we view the T&D businesses as lower risk than the generation businesses that are included in many fully integrated electric utilities.

Ameren Illinois' business risk profile is also affected by its ability to manage its regulatory risk. Earlier in 2010, Standard & Poor's revised its assessment of the Illinois regulation to 'less credit supportive' from 'least credit supportive'. The change reflected our view that the Illinois legislative and regulatory environment had returned to relative stability following the disruption during the state's transition to competition. Our revised assessment was partially based on the 13 constructive rate case orders from 2008 until the early 2010. These developments clearly pointed to a decreasing regulatory risk. However, in April 2010, Ameren received a $4.7 million rate case order for its Illinois electric and gas businesses that we viewed as not conducive to credit quality. Since then, based on error corrections and a rehearing, Ameren's net rate order was increased to $44 million. Overall, we view the company's regulatory risk as rising. Should this persist, it could pressure the company's business risk profile, which could harm its credit quality.

Ameren's consolidated satisfactory business risk profile reflects the combination of the excellent business risk profiles of Ameren's regulated businesses offset by the fair business risk profile of Ameren's merchant energy businesses.

Ameren Missouri's excellent business risk profile reflects its recent rate cases and regulatory mechanisms that overall indicate a decreasing regulatory risk. Ameren Missouri is a rate-regulated utility that serves 1.2 million electric and 126,000 gas customers in portions of central and eastern Missouri. The company also has 10,400 megawatt (MW) of generating capacity of which 5,400 MW is base load coal and 1,200 MW is nuclear generation. In 2009 and 2010, the company received credit supportive rate case orders from the Missouri Public Service Commission that includes more than $390 million of base rate increases, a fuel adjustment clause, pension and OPEB trackers, and a cost tracker for vegetation management and infrastructure inspections. Recently, the company filed for a $12 million gas revenue increase and a $263 million electric rate increase. The commission's orders for the gas and electric rate cases are expected by April 2011 and July 2011, respectively. We expect that Ameren Missouri will continue to file rate cases on a frequent basis to reduce its regulatory lag.

GenCo.'s business risk profile is fair. Ameren has 6,500 MW of merchant generation, of which 4,600 MW represent base load coal generation. Although GenCo. has consistently implemented a three-year hedging policy, its long-term profitability is ultimately dependent on the market price of energy. While the unregulated businesses are considerably hedged for 2011, their margins already declined in 2010 due to weak market power prices and are expected to further decline over the intermediate term based on the forward curve. While the company continues to effectively manage those areas that it can directly influence, including reducing its O&M costs and capital spending, sustained weak energy power prices or increased mandated environmental capital expenditures would pressure the merchant business over the intermediate term.

For Ameren Corp. to improve its consolidated business risk profile, it must reduce its merchant business risks by either selling its merchant assets, committing its merchant generation to long-term contracts, or by completing the necessary environment capital expenditures at its merchant business.

Ameren's significant financial risk profile reflects management's proactive 2009 and 2010 decisions to reduce its dividend, issue equity, and reduce O&M costs and capital spending. More recently, the company's financial measures have improved reflecting warmer-than-expected weather, continued cost reductions, and rate case increases. For the 12 months ended Sept. 30, 2010, adjusted funds from operations (FFO) to total debt increased to 23.9% from 21.4% at the end of 2009, adjusted debt to EBITDA improved to 3.8x from 4.3x, and adjusted debt to total capital strengthened to 53.4% from 54.1%. While Ameren's financial measures are expected to remain improved for the short term, we expect that over the intermediate term the financial measures will weaken because of increasing environmental capital expenditures and gradually weaker cash flows from the merchant generation business.

Liquidity

The short-term rating on Ameren is 'A-3'. We view its liquidity as adequate under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors (exceptional, strong, adequate, less than adequate, and weak). Adequate liquidity supports Ameren's 'BBB-' corporate credit rating. Projected sources of liquidity--mainly operating cash flow and available bank lines--exceed projected uses, necessary capital expenditures, debt maturities, and common dividends by about 1.2x. Ameren's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending, its well established bank relationships, its general high standing in the credit markets, and prudent risk management further support our assessment of its liquidity as adequate.

As of Sept. 30, 2010, Ameren and its subsidiaries had more than $1.6 billion available on its $2.1 billion credit facilities after reducing for outstanding borrowings. The company recently entered into the existing credit facilities and they do not terminate until September 2013. The credit facilities require Ameren and its subsidiaries to maintain a maximum debt-to-capital ratio of 65% and as of Sept. 30, 2010, the company was in compliance with this financial covenant.

Ameren's current positive discretionary cash flow is expected to turn negative over the intermediate term as capital expenditures increase. Long-term maturities are manageable with $155 million due in 2011 and $199 million due in 2012. In the fourth quarter of 2010, GenCo. used cash on hand to pay down its $200 million long-term debt maturity. We fundamentally expect that Ameren will continue to meet its cash needs in a manner that is credit neutral.

Recovery analysis

We assign recovery ratings to First Mortgage Bonds (FMBs) issued by investment-grade U.S. utilities, which can result in issue ratings being notched above a utility's corporate credit rating (CCR) depending on the CCR category and the extent of the collateral coverage. The investment grade FMB recovery methodology is based on the ample historical record of nearly 100% recovery for secured bondholders in utility bankruptcies and our view that the factors that supported those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist in the future. Under our notching criteria, we consider the limitations of FMB issuance under the utility's indenture relative to the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, as well as the regulatory limitations on bond issuance when assigning issue ratings to utility FMBs. FMB ratings can exceed a utility's CCR by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories.

Ameren Illinois FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of about 1.3 times supports a recovery rating of a 1 and an issue rating one notch above the CCR. The FMB of the former Central Illinois Light Co. are covered by a separate indenture that enhances its collateral coverage to about 1.7 times that supports a recovery rating of a 1+ and an issue rating two notches above the CCR.

Outlook

The stable outlook on Ameren reflects Standard & Poor's baseline forecast that its adjusted FFO to debt and adjusted debt to total capital will, over the intermediate term, approximate 21% and 50%, respectively. Fundamental to our forecast is the outcome of the company's rate case filings and the market power prices. However, because of the business risk pressures that Ameren Illinois and GenCo. are currently facing, there is less of a cushion at the 'BBB-' corporate credit rating. A downgrade could result if the company is unable to effectively manage its regulatory risk or dark spreads continue to compress so that FFO to debt drops to below 20% on a sustained basis. An upgrade is possible if management decides to no longer support its merchant business.

Table 1.

Ameren Corp. -- Peer Comparison*

Industry Sector: Combo	Ameren Corp.	Allegheny Energy Inc.	Dominion Resources Inc.	Edison International	PPL Corp.
Rating as of Dec. 21, 2010	BBB-/Stable/A-3	BBB-/Stable/--	A-/Stable/A-2	BBB-/Stable/--	BBB+/Stable/--
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	7,491.7	3,260.6	15,690.5	13,108.7	3,174.5
Net income from cont. oper.	611.7	400.2	1,942.7	1,057.0	351.1
Funds from operations (FFO)	1,671.8	793.3	2,278.0	2,660.8	992.0
Capital expenditures	1,785.1	976.9	3,085.4	3,150.8	999.8
Debt	9,055.8	4,288.6	17,740.2	17,398.6	4,834.9
Equity	7,305.2	2,844.1	11,113.6	10,001.5	2,758.6
Adjusted ratios					
Oper. income (bef. D&A)/revenues (%)	28.5	32.3	26.9	34.1	31.4
EBIT interest coverage (x)	3.1	3.2	2.8	2.3	2.8
EBITDA interest coverage (x)	4.4	3.9	3.9	3.3	3.7
Return on capital (%)	8.1	10.7	8.9	9.3	9.2
FFO/debt (%)	18.5	18.5	12.8	15.3	20.5
Debt/EBITDA (x)	4.3	4.0	4.3	4.1	5.0

*Fully adjusted (including postretirement obligations).

Table 2.

Ameren Corp. -- Financial Summary*

Industry Sector: Combo	--Fiscal year ended Dec. 31--				
	2009	**2008**	**2007**	**2006**	**2005**
Rating history	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB/Watch Neg/A-3	BBB+/Watch Neg/A-2
(Mil. $)					
Revenues	7,090.0	7,839.0	7,546.0	6,880.0	6,780.0
Net income from continuing operations	612.0	605.0	618.0	547.0	628.0
Funds from operations (FFO)	2,006.6	1,581.5	1,427.2	1,384.8	1,225.4
Capital expenditures	1,784.0	2,086.3	1,485.0	1,131.5	1,010.2
Cash and short-term investments	622.0	92.0	355.0	137.0	96.0
Debt	9,379.0	9,457.8	8,330.8	7,336.6	6,723.6
Preferred stock	97.5	97.5	97.5	195.0	195.0
Equity	7,962.5	7,081.5	6,871.5	6,794.0	6,172.4
Debt and equity	17,341.5	16,539.3	15,202.3	14,130.6	12,896.0
Adjusted ratios					
EBIT interest coverage (x)	2.8	3.1	3.3	3.6	4.3
FFO int. cov. (x)	4.7	4.4	4.2	4.7	4.7
FFO/debt (%)	21.4	16.7	17.1	18.9	18.2

Table 2.

Ameren Corp. -- Financial Summary* (cont.)					
Discretionary cash flow/debt (%)	(1.1)	(11.1)	(10.6)	(5.1)	(4.4)
Net Cash Flow / Capex (%)	92.6	50.5	61.0	76.2	70.7
Debt/debt and equity (%)	54.1	57.2	54.8	51.9	52.1
Return on common equity (%)	7.6	8.7	9.0	8.4	10.1
Common dividend payout ratio (un-adj.) (%)	59.6	89.7	86.8	95.4	81.4

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of Ameren Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

--Fiscal year ended Dec. 31, 2009--

Ameren Corp. 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
Reported	8,167.0	8,060.0	2,141.0	2,141.0	1,416.0	508.0	1,977.0	1,977.0	359.0
Standard & Poor's adjustments									
Operating leases	243.3	--	38.0	16.3	16.3	16.3	21.7	21.7	--
Intermediate hybrids reported as equity	97.5	(97.5)	--	--	--	5.0	(5.0)	(5.0)	(5.0)
Postretirement benefit obligations	761.2	--	28.0	28.0	28.0	--	44.9	44.9	--
Accrued interest not included in reported debt	110.0	--	--	--	--	--	--	--	--
Share-based compensation expense	--	--	--	15.0	--	--	--	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	48.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(29.0)	--
US decommissioning fund contributions	--	--	--	--	--	--	(3.0)	(3.0)	--
Total adjustments	1,212.0	(97.5)	66.0	59.3	92.3	21.3	58.6	29.6	(5.0)

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
Adjusted	9,379.0	7,962.5	2,207.0	2,200.3	1,508.3	529.3	2,035.6	2,006.6	354.0

*Ameren Corp. 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.

Related Criteria And Research

- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009.
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008.
- Changes To Collateral Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds, Sept. 6, 2007

Ratings Detail (As Of December 29, 2010)*	
Ameren Illinois Co.	
Corporate Credit Rating	BBB-/Stable/NR
Preferred Stock (12 Issues)	BB
Senior Secured (7 Issues)	BBB
Senior Secured (6 Issues)	BBB+
Senior Secured (3 Issues)	BBB/Developing
Senior Unsecured (4 Issues)	BBB-
Corporate Credit Ratings History	
11-Sep-2008	BBB-/Stable/NR
29-Aug-2007	BB/Positive/NR
23-Apr-2007	BB/Watch Neg/NR
05-Oct-2006	BBB-/Watch Neg/NR
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
Ameren Corp.	
Issuer Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured (2 Issues)	BB+
AmerenEnergy Generating Co.	
Issuer Credit Rating	BBB-/Negative/--
Senior Unsecured (3 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.

Rating Action: **Moody's affirms ratings of Ameren Illinois Company upon reorganization**

Global Credit Research - 05 Oct 2010

Approximately $1.8 billion of long-term debt ratings affirmed

New York, October 05, 2010 -- Moody's Investors Service affirmed the Baa1 senior secured, Baa3 senior unsecured and Issuer Rating, and Ba2 preferred stock ratings of Ameren Illinois Company upon the closing of a corporate reorganization combining Ameren's three Illinois utilities into one utility on October 1, 2010. The reorganization was accomplished by merging Central Illinois Light Company (AmerenCILCO) and Illinois Power Company (AmerenIP) with and into Central Illinois Public Service Company (AmerenCIPS), which has been renamed Ameren Illinois Company (AIC), conducting business as "Ameren Illinois". The debt and other obligations of AmerenCILCO, AmerenCIPS, and AmerenIP are now debt obligations of AIC. The rating outlook of AIC is stable.

Moody's assigned a Baa3 senior unsecured bank credit facility rating to three separate bank credit agreements totaling $2.1 billion dated as of September 10, 2010 among Ameren and Union Electric Company (Ameren Missouri, $800 million, the "Missouri Credit Agreement"), Ameren and AIC (Ameren Illinois, $800 million, the "Illinois Credit Agreement"), and Ameren and Ameren Energy Generating Company ($500 million, the "Genco Credit Agreement") and a bank group led by JPMorgan Chase Bank, N.A. as Agent.

Moody's upgraded three issues of Union Electric Company pollution control revenue bonds (Series 1998 A, B & C) totaling $160 million to A3 from Baa1 to reflect the security provided by utility first mortgage bonds and the fact that the underlying rating on the bonds is higher than that the rating of the financial guarantor.

Ratings affirmed:

All debt ratings of Ameren Illinois Company (including all debt of the former Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company); including its senior secured debt at Baa1; senior unsecured debt and Issuer Rating at Baa3; and preferred stock at Ba2.

Ratings assigned:

Ameren/Ameren Missouri Credit Agreement -- Unsecured bank credit facility rating of Baa3;

Ameren/Ameren Illinois Credit Agreement -- Unsecured bank credit facility of Baa3;

Ameren/Ameren Energy Generating Credit Agreement -- Unsecured bank credit facility of Baa3.

Ratings upgraded:

Union Electric Company Pollution Control Revenue Bonds 1998 Series A, B, C rating to A3 from Baa1.

RATINGS RATIONALE

AIC's ratings reflect improved financial metrics exhibited by Ameren's Illinois utility subsidiaries resulting from higher electric and gas delivery service rates implemented in late 2008 and what Moody's had considered to be an improving political and regulatory environment for Ameren in Illinois. However, Moody's views the most recent Illinois rate case outcomes as unsupportive of credit quality, which could put pressure on the utility's financial metrics going forward, although they are expected to remain adequate to support current ratings. A rehearing of the rate cases is pending, with the Illinois Commerce Commission (ICC) staff recently recommending an additional rate increase of approximately $11 million, and a final decision due from the ICC in November. The rate case outcomes have also renewed our concern about political and regulatory risk for the company in Illinois and the stability of AIC's ratings over the long-term is highly dependent on the outcomes of future rate cases and the overall regulatory environment for utilities in Illinois.

AIC maintains an adequate liquidity profile that was recently strengthened on September 10, 2010 when Ameren and its three Illinois utility subsidiaries entered into a new, three-year $800 million, unsecured bank credit agreement, which is now available to AIC following the reorganization. The credit facility is shared with the parent company, which has a maximum borrowing capacity of $300 million. In addition to this credit facility, AIC also participates in a utility money pool arrangement with the parent, giving it access to additional funds, if necessary.

As part of its Illinois utility corporate reorganization, Ameren Energy Resources Generating Company (AERG, unrated) was transferred from AmerenCILCO to Ameren Energy Resources Company, Ameren's unregulated generation holding company. Ameren completed the reorganization to better align its legal structure with its business segment structure, to lower costs, and to generate operational and other efficiencies.

The rating outlook of AIC is stable reflecting Moody's expectation that financial metrics will remain adequate to support its current ratings and that political and regulatory risk for AIC will not increase significantly. The most recent rate case outcomes should be sufficiently mitigated by additional recovery resulting from the pending rehearing process and by management actions to reduce costs and capital expenditures and should not result in a material degradation of these financial metrics. The stable outlook is contingent on future rate case outcomes being more supportive of credit quality.

The AIC ratings could be raised if there is an improvement in the regulatory and political environment for AIC in Illinois; if there are credit supportive distribution rate case outcomes going forward; and if financial metrics remain strong following the reorganization including CFO pre-working capital interest coverage above 3.5x and CFO pre-working capital to debt in the high teens on a sustainable basis. Ratings could be lowered if future distribution rate cases do not provide sufficient rate relief to maintain financial ratios; if there is political intervention in the regulatory process; or if rising costs and other factors put pressure on financial metrics including CFO pre-working capital interest coverage below 3.0x and CFO pre-working capital to debt below 15% for an extended period.

The principal methodologies used in rating these issuers were Regulated Electric and Gas Utilities published in August 2009, and Global Unregulated Utilities and Power Companies published in August 2009. Other methodologies and factors that may have been considered in the process of rating these issuers can also be found on Moody's website.

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Industry Surveys
Natural Gas Distribution

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July 15, 2010

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The next update of this Survey is scheduled for January 2011.

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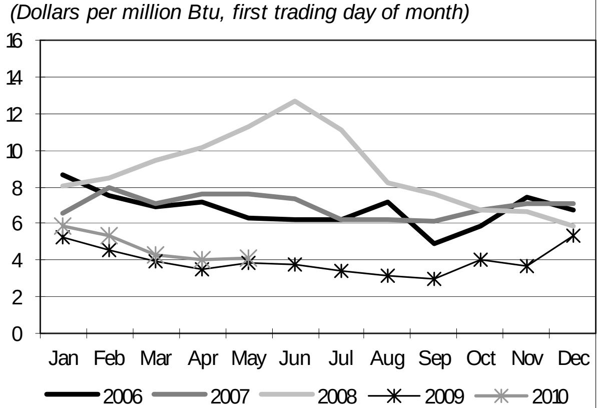
CURRENT ENVIRONMENT

Natural gas rebounds slightly in 2010

Henry Hub spot prices of natural gas have exhibited high levels of volatility over the past decade. That volatility continued in late 2009 and early 2010. Based on data from Bloomberg, after falling to a 2009 low of $1.73 per million British thermal units (MMBtu, Henry Hub spot price) on September 4, 2009, natural gas prices quickly rebounded to a high of $7.98 per MMBtu on January 7, 2010, before falling back to the $4.00 range in mid-March 2010. Prior to the September 2009 low, natural gas prices had declined precipitously from a peak of $13.37 on July 1, 2008. Prior to that peak, prices had risen quickly from a pre-spike low of $5.20 per MMBtu. Prices have been extremely volatile since the September 2009 low, reaching $3.695 per MMBtu on September 25, falling to $2.23 on October 2, rising to $5.06 on October 22, falling to $2.35 on November 13, and then rising to the January 7, 2010, high. In 2009, Henry Hub average bid-week prices (a blend of spot and contract prices in the last week of every month, which is when the largest volume of trading occurs) averaged 54% lower than in 2008. In 2010, Standard & Poor's expects prices to be 2.1% lower than in 2009, with prices generally falling until the third quarter.

Natural gas prices have been very volatile throughout the decade, with four separate spikes over $10 per MMBtu. The first such spike barely brushed past the $10 mark, peaking at $10.53 on December 11, 2000, due to cold weather. The next spike, to $19.38, occurred on February 25, 2003, also due to cold weather with intraday high prices of $13.00 on the day before and $10.75 on the following day. On September 22, 2005, prices reached $14.50, followed by a second spike on December 13, 2005, to $15.52, according to Bloomberg data, related to production cuts caused by Hurricane Katrina. Prices rose throughout late 2007 and early 2008, reaching a peak of $13.37 on July 1, 2008, which we think was due in part to large speculative positions taken by relatively short-term traders. We believe that continued volatility is likely and that price spikes will be a regular occurrence.

HENRY HUB NATURAL GAS PRICE
(Dollars per million Btu, first trading day of month)



Btu-British thermal units.
Source: US Energy Information Administration.

Spot prices are currently below the 10-year bid-week average of $5.83 per MMBtu. According to the Energy Information Administration (EIA), a statistical agency within the US Department of Energy, annual average 2009 wellhead prices fell to $3.71 per MMBtu from a record $7.96 in 2008, which was aided by the high Henry Hub spot prices. Wellhead prices averaged $6.25 per MMBtu in 2007, which was a relatively tame year. Henry Hub spot prices peaked on December 13, 2005, helping to raise the annual average wellhead price for 2005 to what was then an all-time high of $7.33 per MMBtu. In 2006, the annual average wellhead price declined to $6.39 per MMBtu—with gradually declining prices throughout the year, but still substantially above the pre-Katrina 10-year average annual price of $3.15 per MMBtu.

Barring any weather-driven catastrophe or a dramatic decline in inventories, Standard & Poor's believes that average prices will remain below the 10-year average in 2010 and 2011, with some volatility, but less than that seen in 2008. As of June 14, 2010, Standard & Poor's projection for Henry Hub bid-week price was $3.99 per MMBtu in 2010, and $3.74 in 2011.

Currency issues also have an effect on natural gas prices in the US. For example, should the value of the US dollar weaken against the Canadian dollar, the costs of Canadian natural gas could rise, which would put upward pressure on prices. This could increase the attractiveness of regions where production is more expensive, thus allowing additional supplies to enter the market and potentially limiting how high prices could go. Conversely, a significant strengthening of the US dollar against major worldwide currencies could make the US more attractive for cargoes of liquefied natural gas (LNG); the increased supply would put downward pressure on prices. LNG shipments to the US were down sharply in late 2007, 2008, and early 2009, as shipments headed to other countries where prices were higher. However, there was a muted recovery in LNG cargoes entering the US in early 2009, coinciding with a strengthening of the dollar, despite falling US natural gas prices. Late in 2009 and in the first three months of 2010, deliveries were up 4.9%, helped by a 9.2% increase in industrial consumption and healthy growth of 4.6% in residential consumption.

WINTER HEATING SEASON NEAR NORMAL IN 2009–10

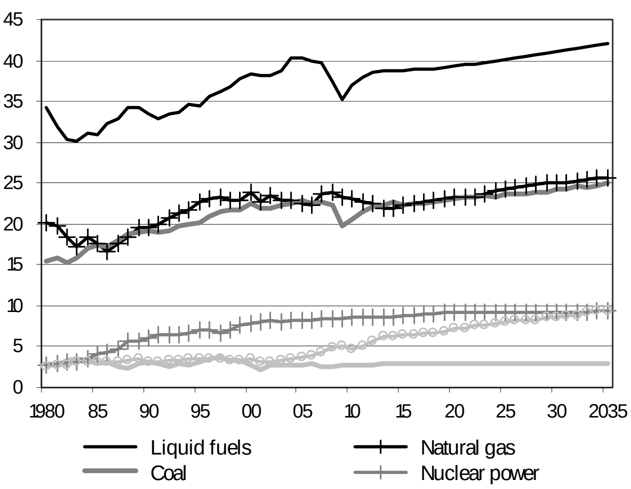
According to data from the National Weather Service's Climate Prediction Center (CPC), the US winter heating season (November through March; generally, the time of peak demand for natural gas) was marked by slightly warmer-than-normal weather in the winter of 2009–10. Using the population-weighted gas home heating data, US heating degree days were 1.2% lower than normal in the 2009–10 season, 0.1% higher than normal in the 2008–09 season, 1.1% below normal in the 2007–08 season, and 7.8% below normal in the 2006–07 season. US heating degree days totaled 3,858 in the 2009–10 season (down 1.3% from the previous season), 3,910 (up 1.2% from the leap year–adjusted 2007–08 season) in the 2008–09 season, 3,863 (up 6.6%) in the 2007–08 leap year adjusted season, and 3,624 (up 2.3%) in the 2006–07 season. (One heating degree day is counted for every degree by which the daily average temperature falls below 65 degrees Fahrenheit.)

There were 20 more heating degree days in the first quarter of 2010 (2,444 total), according to the CPC, despite January and March having 86 fewer heating degree days than the same months a year earlier. The impact of the near-normal first quarter is likely to combine with the projected 3.0% increase in full-year 2010 in end-use consumption (due to the weaker economy in 2009) to help distribution company revenues. At many distribution companies, rate increases and some customer growth should also be beneficial.

Higher consumption seen in 2010

In May 2010, the Energy Information Administration projected that natural gas consumption would climb 3.0% for full-year 2010, but fall by 0.4% in 2011. The projected 2010 consumption increase is higher than the 1.4% 50-year compound annual growth rate in consumption, the 1.0% 25-year growth rate, and the 0.2% 10-year growth rate.

PROJECTED US ENERGY DEMAND
(Quadrillion Btu)



Btu-British thermal units.
Source: US Energy Information Administration.

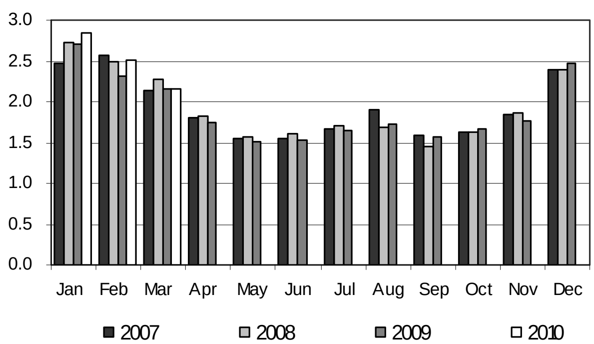
The EIA said that strength in consumption in 2010 would be driven by a recovery in industrial demand and electric power usage, helped by a slightly better economy than last year. For 2011, the EIA said that it expects higher natural gas prices to lead to reduced consumption by power generators, more than offsetting higher growth in industrial consumption. The EIA also said it expects a 2.2% decline in 2011 first-quarter heating degree days to lower space heating demand by the residential and commercial sectors.

In 2009, total natural gas consumption fell by 1.7%, driven by a 7.6% decrease in industrial consumption, a 2.3% drop in residential consumption, and a 0.7% drop in commercial consumption. In the first three months of 2010, natural gas consumption rebounded strongly, rising 4.9%. The growth was driven by 9.2% growth in industrial and 4.6% growth in residential. However, in March 2010, growth appeared to be stagnating, with lower electric power and commercial demand.

Growth in residential consumption of natural gas has been markedly slower over the past 50 and 25 years, with compound annual growth rates of 1.0% and 0.2%, respectively, according to the EIA. However, the 10-year average annual growth rate of 0.1% is lower than that of total consumption, due mostly to strength in electric power consumption during the same period. Because the residential market provides most of the profit for natural gas distributors, ongoing slow growth in consumption and conservation efforts due to historically high prices are likely to continue to pressure earnings growth for distributors that do not have revenue decoupling rate orders in place.

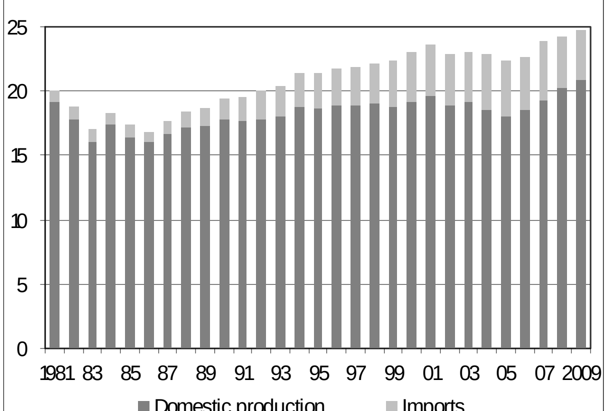
Natural gas usage by electric power generators has grown by 3.6% annually for the past 10 years, more than offsetting a 2.7% average annual decline for industrial users. Average annual commercial demand growth for the past 10 years was 0.2%. Residential, commercial, industrial, power generation, and other usage accounted for 23%, 15%, 29%, 33%, and less than 0.2% of total natural gas delivered in 2009.

US NATURAL GAS CONSUMPTION
(In trillions of cubic feet)



Source: US Energy Information Administration.

US NATURAL GAS SUPPLY
(Trillion cubic feet)



Source: US Energy Information Administration.

From a policy perspective, some energy industry participants question the wisdom of using natural gas for electric power generation: efficiency rates range from 30% to 60%, depending on the type of power plant. Steam generation and gas turbines have ranges in the low end, while combined cycle plants have ranges near the high end. In contrast, modern home furnaces can achieve efficiencies of up to 96%, water heaters up to 86%, and clothes dryers up to 80%. As a result, these people ask whether limited natural gas resources should be squandered on generating electricity when other inexpensive methods of generating power exist.

The bottom line for the natural gas industry is that, as overall energy demand continues to rise, consumption of other forms of energy is rising and filling the gap. In the late 1990s, many forecasters had predicted strong increases in natural gas demand—with total usage going up to 25 trillion cubic feet (Tcf) to 30 Tcf per year, for example—but to date, such growth has not materialized.

The EIA now expects gas demand to grow slowly, rising from 23.2 Tcf in 2009 to 25.6 Tcf in 2035, a cumulative annual growth rate of just 0.4%. The EIA forecasts that the increase will be driven by commercial demand rising 0.7% annually, or 20% in total, to 3.69 Tcf, and industrial consumption rising by 0.5% annually, or 12.9% in total, to 6.72 Tcf by 2035. These forecasts are sharply higher than forecasts made in early 2008, but still slightly lower than forecasts made in early 2007. The EIA now projects that all demand categories will rise between 2009 and 2035. In early 2009, the EIA had said that residential and industrial consumption would fall between 2008 and 2030.

Weak economy curbed demand in '09

Weather is only one variable affecting natural gas consumption patterns; price and the strength of the economy are also important. The relatively high prices of the last few years—a period that saw the advent of oil priced higher than $100 per barrel and natural gas prices above $10 per MMBtu—have hurt demand by encouraging industrial users, which have the option, to switch between natural gas and other fuels. As demand has weakened or remained flat, many companies have struggled to retain profitability.

However, despite the relatively tame natural gas prices, industrial usage in 2009 was 7.6% below such usage in 2008 and 2007, which were nearly the same. While high prices may have slightly affected industrial usage growth earlier in 2008, the recession took its toll in the latter part of 2008 and in 2009. In 2008, total consumption rose at just 0.6%, and in 2009 it fell 1.7%. Through March 2010, industrial demand had a healthy rebound of 9.2%. Standard & Poor's believes that industrial consumption will continue to recover in pace with the overall economy.

In the longer term, several supply-side factors—including increasing production, rising imports of liquefied natural gas, and more pipeline capacity—may put downward pressure on prices, thus leading to increased industrial use. (See the "Industry Trends" section of this *Survey* for more details on these issues.) Some of these factors may also generate increased demand for gas if they improve the reliability of supply and eliminate periodic shortages on the distribution end.

US PRODUCTION INCREASING?

In 2009, total dry natural gas production increased 3.3%, following a 5.3% increase in 2008 and a 4.1% rise in 2007, according to the EIA. [Dry natural gas is defined as the natural gas that remains after liquefiable hydrocarbons (propane, butane, etc.) and sufficient contaminant gases (carbon dioxide, hydrogen sulfide, etc.) have been removed.] The EIA also measures natural gas "gross withdrawals," a figure that includes gas produced from gas and oil wells before various processing steps (including repressuring and the removal of non-hydrocarbon gas) take place. The total dry natural gas production figure is calculated after the extraction loss is deducted from the marketed production figure.

Dry gas production totaled 21.0 Tcf in 2009, slightly below the record production levels of the early 1970s, when annual production routinely exceeded 21.0 Tcf. In fact, 2008 and 2009 were the first years since 1974 that dry gas production exceeded 20 Tcf; it was also the highest level since a more recent peak of 19.6 Tcf in 2001. However, the EIA expects dry gas production to fall for several years before starting a steady climb through 2035 to 23.3 Tcf.

This year started out strongly. Year to date through March 2010, dry gas production rose 0.8% over the comparable year-earlier period. In April 2010, the EIA projected in its *Annual Energy Outlook 2010* that total dry natural gas production would fall 2.9% in 2010, 2.7% in 2011, 0.9% in 2012, and 2.0% in 2013, before starting a relatively steady trend upward. However, in its May 11, 2010, *Short-Term Energy Outlook*, the EIA updated its forecast, stating that it expects natural gas marketed production (which tracks growth in dry gas production very closely) to rise 1.3% in 2010. In the same publication, the EIA projected that marketed production would decrease 0.5% in 2011, hurt by the lagged effect of sustained lower drilling activity in 2010.

US weekly average rig counts increased steadily from 830 in 2002 to 1,879 in 2008, according to data from Baker Hughes, an oil and gas industry consulting firm. The five-year average weekly rig count also increased by an average of 702 rigs over the same period. Keeping that in mind, US rig counts reached a cycle peak at 57.6% above the preceding five-year average in January 2007. From that point until June 2009, the premium to the preceding five-year average for US rig counts slowly dropped, despite continued rises in the actual number of rigs. In December 2008, the actual number of rigs began to decline on a year-over-year basis, with preceding five-year average comparisons slipping into negative territory by February 2009. By June 12, 2009, comparisons had dropped to 44.4% below the average, with the number of rigs falling by 53.9% from the same period in 2008. From June 2009 until February 2010, year-over-year actual rig counts continued to fall, but comparisons to the preceding five-year average continually improved. Since February 2010, actual rig counts have increased to such an extent that comparison to the preceding five-year average turned positive in May 2010.

North American rig counts, according to data gathered from Baker Hughes, started to trend back toward their five-year average, having averaged 26.5% above the average since the beginning of 2008 and reaching

35.0% above the five-year average on September 19, 2008. By December 26, 2008 (the last week reported in 2008) North American rig counts were only 10.3% above the five-year average. North American rig counts continued to plummet through most of 2009, falling 53.8% below prior-year levels or 47.1% below the five-year average on June 12, 2009. Since then, rig counts have rebounded, with weekly rig count comparisons to the prior year turning positive in February 2010 and comparisons with the preceding five-year average breaking even in May 2010.

Increasing rig productivity may account for the relatively steady production despite a falloff in rig counts. According to a report from Platts (which, like Standard & Poor's, is a unit of The McGraw-Hill Companies), the average number of wells per rig increased to 1.5 in early 2009, from 1.0 in 2005. Using horizontal and directional drilling techniques, operators are now able to drill several wells per rig. The EIA attributes the continued strong production in 2009 to new supplies from unconventional gas fields, such as shale plays, and a return of some Gulf of Mexico production that was shut in due to damage from Hurricanes Gustav and Ike in 2008.

Minimal current production impact from Gulf oil spill

The Gulf of Mexico oil spill that started on April 20, 2010, is not likely to have a major effect on natural gas production in the Gulf of Mexico (GOM), in Standard & Poor's view. According to the Minerals Management Service—an agency of the US Department of the Interior that manages the nation's natural gas, oil, and other mineral resources on the outer continental shelf—only two rigs, producing less than 0.1% of daily Gulf gas production, had been shut down due to the oil slick, as of May 2, 2010. Even if the slick shuts down more platforms, Standard & Poor's thinks it unlikely that natural gas production would be significantly curtailed. US offshore production in the GOM represented 10.1% of total US natural gas production in 2008. Texas offshore production, which is unlikely to be affected by the spill, represents at least 0.2% of the total US production. Production disruptions from a major hurricane would be more likely to affect GOM production, but a drilling moratorium is likely to reduce future GOM production gains.

On May 27, President Obama extended the moratorium on deepwater drilling to six months, postponed exploratory drilling planned for this summer off Alaska's coast, and canceled Western GOM and Virginia lease sales. The ban on new drilling permits extended to any operation in over 500 feet of water, and any permitted wells currently being drilled in the deepwater (not counting emergency relief wells being drilled) GOM will be required to ease operations as soon as safely possible. As of May 26, the Department of Interior estimated there were 33 mobile operating drilling rigs in the deepwater GOM in different stages of drilling and preparation that will be affected. As a result, Standard & Poor's estimates that while the moratorium will likely have an enormous short-term impact on drilling activity in the Gulf of Mexico, we currently see minimal impact on current oil and gas production levels.

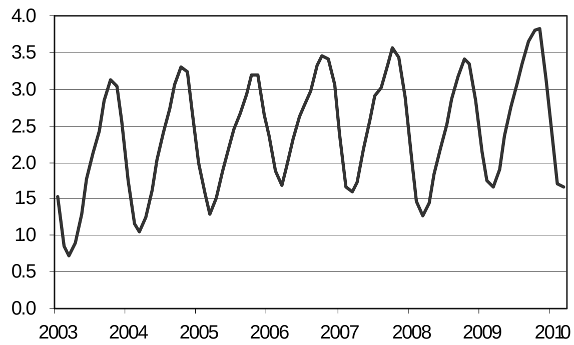
By contrast, one week after Hurricane Katrina made landfall in August 2005, Gulf natural gas production declined 8.35 Bcf/d, which represented 83.5% of GOM production at the time. By December 2, 2005, 29.1% continued to be shut-in and on December 22 of that year, 19.4% was still unavailable. In addition to causing damage to some rigs, the hurricane damaged natural gas processing facilities, which strip impurities from raw natural gas so that the gas can enter the pipeline system.

LNG imports rebounding slightly

One element that has been added to the mix of the natural gas distribution business recently is the amount of LNG being imported into the US. In 2008, imports of LNG averaged 0.96 billion cubic feet per day (Bcf/d), the lowest level since 2002 and down 54% from 2007. LNG imports in 2009 rose 28.5% to 1.24 Bcf/d, but were still 41% below 2007 levels.

In its May 11, 2010, *Short-Term Energy Outlook*, the EIA predicted LNG imports in 2010 will rise to between 1.6 and 1.7 Bcf/d, roughly in line with its *Annual Energy Outlook 2010*. Reasons for the projected increase include the start-up of new liquefaction capacity in Qatar, Yemen, and Peru. Despite increasing demand abroad for LNG during the winter months, the EIA believes that the new liquefaction capacity was likely to lead to increasing shipments to the US through the end of the year. Through March 2010, LNG shipments arrived at a 1.55 Bcf/d pace, versus 0.96 Bcf/d for the same period a year earlier. In 2011, the EIA expects LNG imports to continue their rebound to 1.91 Bcf/d for reasons similar to those fueling the projected 2010 increase. (For more details about new LNG facilities, see the “Industry Trends” section of this *Survey*.)

SEASONAL VARIATIONS IN WORKING NATURAL GAS UNDERGROUND STORAGE VOLUMES
(Trillion cubic feet)



Source: US Energy Information Administration.

Will inventory levels reach a new record?

The amount of working gas in storage in the lower 48 states totaled a record 3,837 Bcf as of November 27, 2009, according to EIA estimates. Stocks were 479 Bcf (14.3%) higher than a year earlier, and were 503 Bcf (15.1%) higher than the five-year average. Through May 21, 2010, inventory levels were 56 Bcf (2.5%) higher than a year ago and 271 Bcf (13.6%) higher than the preceding five-year average. The EIA forecasts October end-of-injection-season inventories of 3,800 Bcf, slightly below the record level reached in 2009. This forecast is plausible, in our view, given expectations for increased use of natural gas by electric power generators during summer 2010. The high storage levels are likely to continue to keep pressure on natural gas prices through the remainder of 2010.

AVERAGE NUMBER OF RATE CASES LIKELY

Year to date through June 2, 2010, 20 rate cases had been completed, according to Regulatory Research Associates (RRA), a regulatory consulting firm that is a division of SNL Financial. Recently, there were another 30 rate cases filed, with substantially all likely to be completed by the end of 2010, according to the RRA. The five-year average for rate cases completed is 35 per year.

The average requested return on equity (ROE) for pending rate cases is 11.28%, with an average requested equity to total capitalization (equity component) of 50.8% and an average requested return on rate base (RORB) of 8.73%. For rate cases completed since 2003, the average ROE granted was 10.4% (versus a requested ROE of 11.5%); the average RORB granted was 8.36% (versus 9.00% requested). In observable cases, granted rate base was $1.65 billion (or 1.82%) less than rate base requested for the period.

During 2010, completed rate cases had an ROE of 10.04%, an RORB of 8.06%, and an equity component of 48.2%, versus requested amounts of 11.19%, 8.74%, and 48.8%, respectively. For cases through June 2, 2010, the granted rate base was $399 million (or 3.6%) lower than requested, though $221 million of the shortfall was from three companies: Peoples Gas Light and Coke Co. ($99 million), Illinois Power Co. ($66 million), and CenterPoint Energy Inc. ($56 million). In 2009, observable granted rate base was $508 million (or 5.07%) less than rate base requested, with a majority of the shortfall from two companies, Northern Illinois Gas Co. ($179 million) and Hope Gas Inc. ($94 million). (See the “How the Industry Operates” section of this *Survey* for further discussion of rate-setting mechanisms.)

Notable rate cases completed to date in 2010 included Peoples Gas Light and Coke, which filed for a $113 million rate case, premised upon an 11.9% ROE, a 9.10% RORB, and an equity-to-capitalization ratio of 56.00%. The company received a $69.8 million increase, based on a 10.2% ROE, an 8.05% RORB (with a significantly lower rate base as mentioned above), with no change to the requested equity level. Consumers Energy Co. filed for an $89 million increase, based on an 11.0% ROE, a 7.28% RORB, and an equity-to-capitalization ratio of 41.07%. It received a $66 million increase based on a 10.6% ROE, a 7.02% RORB, and an equity level of 40.78%.

One notable rate case was filed on June 9, 2009, by Michigan Consolidated Gas Co. (MCGC), a subsidiary of DTE Energy Co. MCGC initially filed for a $193 million rate increase, but subsequently reduced the request to $175 million, based on new depreciation rates implemented on March 18, 2010. On January 1, 2010, the company implemented an interim $170 million rate increase. MCGC sought an RORB of 7.35% (7.19% received in rate order) and an ROE of 11.25% (11.00%), with a 39.8% (38.78%) equity component. The final rate order was authorized on June 3, 2010. Because the Michigan Public Service Commission approved a rate increase of $118 million (versus the $170 million MCGC implemented on January 1), the company will have to issue a refund proposal. Also included in the approval was a pilot revenue-decoupling mechanism that, according to the RRA, "utilizes weather-normalized, as opposed to actual, revenues, in order to exclude revenue variances due to abnormal weather from the mechanism."

Another notable rate case was filed on April 29, 2008, by Northern Illinois Gas Co. (NIGC), a subsidiary of NICOR Inc. In that case, NIGC filed for a 25% revenue increase, or $140 million. Even with the requested increase, the company would still have been one of the lowest-cost distributors of gas in its state. The company sought a 9.27% RORB and an 11.15% ROE, with a 56.8% equity component. On March 25, 2009, regulators authorized an increase of just half the requested amount, but upon appeal, the rate hike was increased to $80.2 million. The approved ratios were an 8.09% RORB and a 10.17% ROE, with a 51.1% equity component.

Notable pending rate cases include a $213 million rate case filed by Pacific Gas and Electric Co., a $161 million case filed by Consolidated Edison Co. of New York, a $79 million case filed by Boston Gas Co., and a $74 million case filed by Public Service Electric Gas. The Pacific Gas and Electric Co., the Consolidated Edison Co. of New York, and the Boston Gas Co. cases were expected to be decided in the second half of 2010; the RRA has not estimated the date for the case filed by Public Service Electric and Gas Co.

PENDING RATE CASES
(As of June 2010)

STATE	COMPANY	FILING DATE	RATE INCREASE (MIL.$)	RETURN ON RATE BASE (%)	RETURN ON EQUITY (%)	COMMON EQUITY TO TOTAL CAP. (%)	RATE BASE (MIL.$)	ACTION LIKELY BY
California	Pacific Gas and Electric Co.	12/21/2009	213.0	8.79	11.35	52.0	2,472.0	12/31/2010
Georgia	Atlanta Gas Light Co.	5/3/2010	54.1	8.52	11.25	51.0	1,317.5	11/2/2010
Idaho	Avista Corp.	3/23/2010	2.6	8.55	10.90	50.0	101.4	NA
Indiana	Northern IN Public Svc Co.	5/3/2010	0.0	7.69	11.75	59.0	318.0	5/1/2011
Kansas	Atmos Energy Corp.	1/29/2010	6.0	9.11	11.40	49.5	144.6	9/27/2010
Kentucky	Delta Natural Gas Co.	4/23/2010	5.3	8.66	12.00	44.5	110.5	10/22/2010
Kentucky	Louisville Gas & Electric Co.	1/29/2010	22.6	8.32	11.50	53.9	466.5	8/31/2010
Massachusetts	Boston Gas Co.	4/16/2010	79.2	9.66	11.30	53.6	982.7	10/31/2010
Massachusetts	Colonial Gas Co.	4/16/2010	26.8	9.65	11.30	54.0	242.9	10/31/2010
Maryland	Baltimore Gas and Electric Co.	5/7/2010	42.4	8.99	11.65	52.0	848.9	12/7/2010
Michigan	Michigan Consolidated Gas Co.	6/9/2009	192.6	7.32	11.25	38.9	2,359.0	6/9/2010
Minnesota	Northern States Power Co. - MN	11/12/2009	16.2	8.80	11.00	52.5	440.6	12/13/2010
Missouri	Atmos Energy Corp.	12/28/2009	6.4	8.86	10.90	49.4	66.5	10/28/2010
Missouri	Laclede Gas Co.	12/4/2009	60.7	9.17	11.13	57.5	755.0	11/7/2010
Montana	NorthWestern Energy Division	10/16/2009	2.0	8.30	10.90	49.5	256.6	10/16/2010
Nebraska	Black Hills Nebraska Gas	12/1/2009	12.1	9.84	11.50	52.0	163.8	8/31/2010
New Hampshire	EnergyNorth Natural Gas Inc	2/26/2010	11.4	9.10	11.20	50.0	169.0	NA
New Jersey	Public Service Electric Gas	5/29/2009	74.0	8.73	11.25	51.2	2,338.1	NA
New Jersey	South Jersey Gas Co.	1/15/2010	63.7	8.89	11.50	54.0	857.9	10/15/2010
New York	Central Hudson Gas & Electric	7/31/2009	4.0	7.58	10.00	48.0	190.0	NA
New York	Consolidated Edison Co. of NY	11/6/2009	160.8	8.1	10.8	48.2	3,093.3	9/30/2010
New York	NY State Electric & Gas Corp.	9/17/2009	54.9	8.66	11.43	48.0	495.3	8/15/2010
New York	Rochester Gas & Electric Corp.	9/17/2009	59.0	9.41	11.43	48.0	425.9	8/15/2010
Pennsylvania	Columbia Gas of Pennsylvania	1/28/2010	32.3	8.91	11.70	52.0	701.2	10/28/2010
Pennsylvania	PECO Energy Co.	3/31/2010	43.8	8.95	11.75	53.2	1,099.6	12/31/2010
Virginia	Columbia Gas of Virginia Inc	5/3/2010	13.0	8.57	11.50	43.9	392.2	NA
Washington	Avista Corp.	3/23/2010	8.5	8.33	10.90	48.4	199.2	2/23/2011
Wisconsin	Madison Gas and Electric Co.	4/22/2010	4.4	8.77	10.40	57.3	137.1	12/31/2010
Wisconsin	Wisconsin Public Service Corp	4/1/2010	5.0	8.57	11.25	53.6	366.9	12/31/2010
Wyoming	SourceGas Distribution LLC	2/26/2010	7.5	9.17	12.30	50.3	103.6	12/31/2010

NA-Not available.
Source: Regulatory Research Associates.

CAP & TRADE: A POTENTIAL DETRIMENT FOR NATURAL GAS?

On May 12, 2010, the US Senate introduced S. 1733—the Clean Energy Jobs and American Power Act—a bill that is similar to, but shorter than, the Waxman-Markey bill that was passed by the US House of Representatives on June 26, 2009. Among other things, the bill establishes a cap and trade system for carbon dioxide and carbon dioxide equivalents.

According to the US Environmental Protection Agency (EPA), "Cap and trade is an environmental policy tool that delivers results with a mandatory cap on emissions while providing sources flexibility in how they comply." A cap and trade system sets a limit on total emissions allowed and then provides allowances to each emissions source that they can trade based on their need or excess. As emissions are produced, an emissions source surrenders the allowances equal to its emissions. Because coal plants produce large quantities of carbon dioxide, a cap and trade system would likely result in a shift away from coal-fired power production toward renewable energy and natural gas–fired power production.

Among other things, the bill provides 85% of allowances at no charge, with the remainder to be auctioned. However, due to the sharp decline in the number of allowances provided over the years, Standard & Poor's believes emission allowance limits will eventually make it unprofitable to produce electricity from natural gas, use natural gas for manufacturing purposes, and make it prohibitively expensive to provide space heat. As a result, even if the bill passes and becomes law now, Standard & Poor's believes pressure on the economy may encourage voters to elect a government that would repeal many provisions of this bill.

The EIA predicts that natural gas use in the US will emit 1,345 million metric tons of carbon dioxide in 2035. Assuming natural gas were the only source of carbon dioxide emissions in the US, this would not be a problem until later, as total emission allowances fall below the level of only natural gas US carbon dioxide emissions sometime in the 2040–2050 period. If such a bill passes and is not repealed or changed, the gas industry could be thrown for a loop. However, S&P believes problems would likely start much more quickly, if not immediately, as scarcity of allowances would drastically increase energy prices, in our view.

According to the bills, carbon dioxide equivalent emissions in 2005 were 7,206 million metric tons. (Other emission gases are assigned an equivalent equal to a certain number of carbon dioxide emissions; *e.g.*, one metric ton of methane is equal to 25 equivalents, and one metric ton of nitrous oxide is equal to 298 equivalents.) In 2013, the year that emission allowances are first issued under the Senate bill (2012 in the House version), only 4,722 million metric tons of allowances (4,627 in the House bill) would be issued. In 2050 and thereafter, the bill provides only 1,043 million metric tons of allowances (slightly more than the 1,035 in the House version), only 22% of the level that was allowed in 2012 and 2013, and 14% of the total 2005 carbon dioxide equivalent emissions cited by the bills. Standard & Poor's believes resultant (drastically) higher prices to purchase emissions allowances would likely impede future economic activity, which in turn could harm natural gas utilities.

Standard & Poor's believes the bill's passage would initially benefit gas utilities, as power generators would likely shift their fuel to natural gas from coal. However, as the number of available allowances continues to decline, prices of traded and auctioned credits would skyrocket due to competition between use of allowances for natural gas, coal, and industrial purposes, in S&P's view. The increased use of natural gas by power generators would also likely put upward pressure on natural gas prices.

Soaring energy prices are likely to lead to extreme conservation efforts, thus decreasing throughput on natural gas utility distribution systems, in Standard & Poor's opinion. From a commercial standpoint, S&P believes businesses that could not purchase enough allowances to manufacture their products might have to shift production overseas, especially for goods that would have been exported from the US, further reducing natural gas throughput on distribution systems. Standard & Poor's believes that, over time, the result would be much lower demand for natural gas as it becomes much more expensive to use.

Standard & Poor's believes that declining distribution system throughput would likely cause harm to natural gas utilities, even to those that have revenue decoupling in place (a rate system designed to allow a utility to earn its allowed return on equity, even if the weather causes a drop in gas usage). Without revenue decoupling, lower usage leads directly to fewer revenues with which to cover fixed investment and thus a more challenging time in earning the allowed return on equity. Even with revenue decoupling, Standard & Poor's thinks an increasing number of customer disconnects could hurt a utility's ability to earn the allowed return on equity.

Standard & Poor's believes the risks presented by this bill are uncertain, as the bill may not become law. We believe that the failure of such a bill to pass would be beneficial for the US natural gas utilities in the long term.

OUTLOOK: CAUTIOUSLY OPTIMISTIC

Gas distribution companies generally saw slow growth in 2007, 2008, and 2009. Standard & Poor's expects regulated gas utility subsidiaries to report earnings growth in the low to mid–single digits, helped by rate increases, some improvement in industrial sales, and customer growth, but offset by customer conservation efforts. Warm winter weather in the fourth quarter could also have a negative effect on 2010 results. While we see somewhat of a rebound in industrial sales, we believe that the pace of economic expansion in this recovery appears to be slower than many other economic recoveries. Additionally, we believe that bad debt expenses will remain above normal levels, as initial jobless claims linger at levels in the mid-400,000 range and unemployment remains close to 10%. Despite these challenges, residential and commercial customer growth usually remains positive throughout the entire economic cycle, helped by population growth.

US demand for natural gas is expected to rise in 2010, but fall in 2011. The EIA forecasts that US natural gas consumption will climb 3.0% in 2010 and fall 0.4% in 2011, after a 1.7% decline in 2009, a 0.7% rise in 2008, and a 6.5% rise in 2007, which was helped by more normal weather than in the prior year.

A return to continued historically high natural gas prices could hurt gas companies. On June 14, 2010, Standard & Poor's forecasted Henry Hub bid week prices would average $ 3.99 in 2010 and $3.74 in 2011. Current gas prices and forecasts are relatively low compared with recent history. Lower prices tend to attract more new customers to gas and encourage switching from other fuels; additionally, current high prices for some competing fuels might make gas the more attractive alternative. Low gas prices could decrease the scrutiny that regulators apply to utilities' requests for gas supply reimbursement or for higher distribution rates.

Economic, natural, political, and geopolitical events could derail the natural gas price and volume forecasts for 2010. The slowdown in world economic growth and the strengthening of the US dollar from the summer of 2008 through early 2009, for example, led to oil prices falling from their record highs. From March 2009 until November 2009, the US dollar weakened significantly, adding to upward pressure on oil prices. Since November 2009, the US dollar has strengthened, but global oil supply and demand factors have helped to keep oil prices from falling dramatically. So far, this has not translated into drastically higher natural gas prices due to high storage levels, relatively weak demand, and the potential for additional LNG cargoes. Continued slow growth in both the US and global economies could continue to curb gas demand growth. Increased LNG liquefaction capacity worldwide may lead to more LNG imports, adding new supplies to the US markets. Additionally, new pipelines stretching from the Rocky Mountains eastward could reduce price volatility in the Northeast, putting a limited amount of downward pressure on prices.

Other developments, however, could increase upward pressure on prices. Faster than expected economic growth could cause natural gas demand to drain some of the gas in storage, leading to a price environment that could favor higher prices. At any point, the federal government could limit or discourage investment in US gas drilling through measures that would raise the cost of drilling in the US, making LNG and Canadian pipeline imports more attractive. Possible tensions between the US and oil-producing nations could lead to higher oil prices, which may also cause upward pressure on natural gas prices as end users with the capability to switch fuels could increase the demand for gas if it is less expensive relative to oil. Likewise, a significant increase in coal prices could also put upward pressure on natural gas prices as electric generators might favor burning gas in combined cycle plants over burning coal in smaller, less efficient, coal plants. ■

INDUSTRY PROFILE

A regulated industry confronts volatile prices

Natural gas distribution utilities include several kinds of operations: regulated, investor-owned companies; municipal gas distribution systems owned by cities and counties; and special utility districts. This *Survey* covers investor-owned gas distribution companies only; it does not cover interstate pipelines or natural gas production companies, nor does it cover any issues related specifically to municipally-owned gas distribution utilities.

Local distribution companies (LDCs) served 70.8 million customers in 2008 (as of May 28, 2010, data for 2009 had not yet been released), up 0.4% from 2007, according to the Energy Information Administration (EIA), a statistical agency within the US Department of Energy. Of this total, 65.3 million were residential accounts using gas mostly for home and water heating and cooking. The remaining customers were commercial (5.3 million), industrial (0.2 million), and power generators. (See the "How the Industry Operates" section of this *Survey* for details.)

GAS UTILITIES OWN MORE THAN LDCs

	% OF 2009 OPER. INC. FROM GAS LDC OPERATIONS	GAS UTILITY	REGULATED ELECTRIC UTILITY	ELECTRIC POWER GENERATION	WHOLESALE GAS MARKETING	E&P	PIPELINE & STORAGE	OTHER
GAS UTILITIES								
AGL Resources	67	●			●		●	
Energen Corp.	19	●				●		
Equitable Resources Inc.	22	●			●	●	●	
National Fuel Gas	23	●		●	●	●	●	●
Nicor Inc.	68	●			●		●	●
Oneok Inc.	23	●			●		●	
Questar Corp.	10	●			●	●	●	
WGL Holdings Inc.	89	●			●			●
MULTI-UTILITIES								
Alliant Energy	13	●	●	●				●
MDU Resources Group Inc.	16	●	●			●	●	●
Scana Corp.	8	●	●		●		●	●
Nisource Inc.	41	●	●		●		●	●

E&P-Exploration & production.
Source: Company reports.

A series of regulatory reforms from 1978 (when regulations that set natural gas prices at the wellhead were first loosened) to 2005 (when the Public Utilities Holding Company Act, or PUHCA, was repealed, which dropped federal restrictions on utility mergers) have created a vastly different operating environment than that which prevailed 35 years ago. Natural gas prices are generally higher and more volatile, energy markets are more competitive, and corporate mergers have created huge, diversified energy companies with trading capabilities across several different energy sources. These developments have generated new risks—as well as new potential rewards—for gas distribution utilities.

Responding to this environment over the past decades, previously independent gas utilities have combined with other regulated utilities, as well as with new, unregulated energy-related businesses, to manage these new risks and profit from new opportunities. As a result, today's LDCs are usually part of a holding company that operates several different businesses. In some instances, LDC operations are the holding company's primary business. Secondary operations may include wholesale gas marketing, unregulated power generation, oil and gas exploration and production, interstate pipelines and storage, or even non–energy-related businesses such as timber or containerized shipping. In many other cases, LDCs are relatively small parts of large multi-utility or multi-industry companies.

INDUSTRY TRENDS

Several important trends in US energy markets are having a powerful influence on today's natural gas distributors. US natural gas prices are among the highest and most volatile in the world, due to the combination of rising gas demand and a lack of domestic production growth. On occasion, however, local events overseas, such as the shutdown of a nuclear plant in Japan and its using natural gas–fired plants to compensate, can lead to higher prices there. US gas demand is increasingly being met by imports, a situation that creates new risks and opportunities for LDCs or their affiliates. The growth in imports means that higher prices overseas could lead to competition for gas supplies, though new export facilities are easing this risk.

A trend among state regulators—to "unbundle" an LDC's supply function from its delivery function and thereby introduce retail competition into the supply of natural gas—has generated little interest in serving residential customers. Competitive suppliers are able to make substantially more money serving large commercial and industrial customers. At the same time, LDCs are likely to remain rate-regulated businesses, with limited opportunities for growth within their service areas. Many LDCs have taken advantage of industry deregulation to acquire other kinds of businesses in hopes that diversification will drive stronger profit growth.

HIGHER AND MORE VOLATILE NATURAL GAS PRICES

The natural gas industry has undergone substantial changes in recent decades. Since regulatory reforms to the long-distance pipeline industry began in 1984, market forces have created a much more efficient supply system than existed previously. In the initial years of pipeline deregulation, increased efficiencies reduced transportation charges and inflation-adjusted gas prices. Lower and more transparent market prices fueled demand growth, while the elimination of structural constraints allowed natural gas supplies to be more fully developed, thus reducing levels of untapped capacity. Demand expanded to meet the limits of available supply.

With long-term forecasts for slowly increasing demand, growing production from more expensive wells, and steady domestic production, natural gas prices have been trending higher. Increasing summertime usage by power generators had reduced or eliminated storage additions during the summer months; this, combined with constrained natural gas pipeline and storage capacity in certain regions, has led to much more volatile natural gas prices.

This phenomenon has complicated the short-term operations and long-term investment planning for the entire natural gas industry, including regulated LDCs. Since December 2000, when cold weather blanketed the eastern United States and exhausted available gas supplies in some areas, natural gas prices have become noticeably more volatile; prices surged again to near-record levels during two subsequent winters. Since 2000, natural gas prices have been sustained throughout the year at higher levels than had been experienced in the past.

Price spikes

Since 2000, US natural gas prices have experienced severe spikes caused by cold winter weather, as well as one caused by hurricane damage to offshore production platforms and a spike that began toward the end of the 2008 heating season and culminated with an unusual mid-summer peak.

◆ **Cold weather spikes early this decade.** In December 2000, cold weather blanketed demand centers in the eastern and Midwestern United States, causing demand to spike and gas inventories to decline. By the end of that month, gas in storage was 10% less than the previous record low recorded in 1976. After averaging what was (at the time) an outstandingly high price of $4.50 per million British thermal units (MMBtu) in November 2000, natural gas for delivery at the Henry Hub (the national benchmark) in Louisiana more than doubled in December, reaching a then-record $10.52 per MMBtu on the New York Mercantile Exchange (NYMEX) on December 29.

Prices for gas delivered at the city gate (which is where LDCs take delivery from interstate pipelines) rose much further. With all available gas being committed to the frozen North, there was precious little to send to other demand centers. On December 11, 2000, the price for natural gas delivered to the southern California border reached a previously unimaginable $68 per MMBtu. At the time, the Energy Information

Administration (EIA), a statistical agency within the US Department of Energy, estimated that the average residential heating bill would rise by 70% for the winter—the biggest season-to-season gain since 1975.

After a relatively mild winter in 2001–02, another spike occurred when a cold snap hit in February 2003, driving the Henry Hub spot price on February 25 to $22.00 per MMBtu—nearly twice the level in 2000. However, prices dropped back to less than $6.00 per MMBtu the following week. Later that year, a blast of cold weather in December 2003 drove futures prices on the NYMEX up by 50% in two weeks, even though storage levels were above their five-year average and demand was running well short of peak levels. More cold air in the winter of 2003–04 pushed futures prices to $8.75 per MMBtu in February 2004, while gas delivered to New York City reached $40 per MMBtu.

◆ **Hurricane-related spike in 2005.** A sharp spike in prices occurred in September 2005, when two massive hurricanes, Katrina and Rita, struck a direct blow to the Gulf of Mexico's oil and gas industry over a four-week period beginning in late August. Together, the storms destroyed 115 offshore production platforms and damaged 52 other platforms and 183 pipelines. Damage was so severe that half of the Gulf's output, which provides about 25% of the US gas supply, was still out of operation two months later. The loss of supply drove gas futures prices above their previous record, set in December 2000, to $15.38 per MMBtu in December 2005.

◆ **Oil price–related spike.** Another longer-lasting price spike occurred initially in concert with record high oil prices, with prices starting their spike upwards after a short-term closing low of $5.34 per MMBtu (Henry Hub) on August 27, 2007. However, the upward run of prices paused during the last two months of 2007 in the $7.00 range. From the start of 2008 until the intraday market peak of $13.41 per MMBtu on July 2, 2008, gas prices rose dizzyingly fast, even though inventory levels were only 3% below their five-year average. (In fact, inventory levels were likely lower than the average as a direct result of the high gas prices.) Following the July peak, natural gas prices plunged even faster than they went up and faster than oil prices fell, reaching the recent Henry Hub intraday low of $3.15 per MMBtu by April 27, 2009.

What do these price spikes mean?

These price spikes made national headlines and caused considerable anxiety among regulators, politicians, and LDCs, and spawned at least one Senate committee hearing. Were suppliers gouging consumers? Had speculators driven up prices unnecessarily? Was there a gas crisis? The Commodity Futures Trading Commission, a government agency, investigated some of the spikes and found no evidence of market manipulation. Another investigation in the wake of the hurricanes had similar findings. However, a congressional investigation into high energy prices in the summer of 2008 heard testimony that blamed the 2008 oil price spike on foreign currency changes and to substantially increased participation of speculative funds in the oil markets.

High gas prices are an area of concern for gas utilities—even though their earnings are not tied directly to gas prices in the way that those of the exploration and production companies are—because they spur customers to conserve energy or search for other, cheaper sources of energy. Higher gas prices also invite closer regulatory scrutiny of gas purchases that, in hindsight, may be difficult to justify. A study on price volatility released in 2003 by the American Gas Foundation, an industry research group, said that volatility "has become the most significant issue facing the natural gas industry and its companies."

SUPPLY/DEMAND BALANCE IMPROVING IN THE FUTURE?

In the recent past, a supply/demand imbalance appeared to be building, with demand exceeding production and availability of Canadian pipeline imports being called into question. This led to an expansion of LNG capacity that would allow the US to receive overseas imports. However, new demand and production forecasts from the EIA continue to raise the question about whether additional LNG plants are needed. According to EIA forecasts, 93.9% (23.33 Tcf) of total consumption (24.86 Tcf) will be met by gas produced in the US, with 3.3% (0.83 Tcf) being met by LNG imports and 2.6% (0.64 Tcf) being met by pipeline imports. Standard & Poor's believes that this forecast suggests that there are ample supplies of natural gas and, if prices in the US are not high enough to attract LNG or pipeline shipments, then production inside the US could be ramped up to compensate.

Tighter supply/demand balance over past decade

While the spikes in prices alarmed gas consumers, they were all relatively short-lived. More worrisome, however, is a parallel development of sustained increases in average annual gas prices occurring for most of the past decade. Average US natural gas prices have risen in seven of the past ten years; and in 2010, Standard & Poor's expects prices to be 75% higher than the $2.27 in 1999, despite the fact that S&P expects prices to be lower than in any of the past seven years.

Behind the rise is a fundamental tightening of the balance between gas supply and demand. For the past several years, natural gas production in the United States has been stagnant—due, in large part, to declining output from the nation's largest and cheapest gas fields. During 1998 and 1999, oil and gas prices were depressed because of slumping global demand in the wake of the Asian economic meltdown in 1997. The losses suffered by many large producers from the drop in prices left them highly cautious about making new investments to expand production. The fact that they were becoming increasingly reliant on gas produced from risky and more expensive, deepwater wells, which cost hundreds of millions of dollars each to drill, only added to the caution. Moreover, through 2008 rig count had more than doubled since 2000, indicating that newer wells are producing at only a fraction of the rate for older wells. Adding to this, the recent relatively modest declines in 2009 total demand led to a dramatic drop in 2009 summer rig counts, though in 2010 rig counts have rebounded to 84% of levels in 2008, 75% higher than the same period a year ago. As a result, production is expected to increase by 1.3% in 2010.

Since the mid-1990s, demand for gas from electric power generators has increased, as environmental regulations and high electricity prices encouraged the development of new power-generation capacity fired by natural gas. By 2009, the amount of gas used to generate electricity had risen by 69% since 1997, when the Department of Energy first started tracking this statistic, or a 4.5% annual growth rate. The rise in gas-fired generation capacity has not only kept the overall demand for gas from falling dramatically, thus tightening the supply/demand balance, but it has also made demand more volatile. Use by generators in 2009 has increased 3.3% despite a drop in usage across nearly all other demand categories as relatively low gas prices made it more advantageous for power producers to run natural gas plants rather than some of their lower efficiency coal plants. In its May 11, 2010, *Short-Term Energy Outlook*, the EIA said that it expected electric power usage to lead total consumption higher in 2010.

Much of the gas-fired generation capacity that was built is "peaking" capacity—used only for short periods of time when electric power demand is highest. These plants, which are cheaper and faster to build and more responsive to demand changes than coal-fired or nuclear power plants, are designed to be started and stopped on very short notice, thereby producing sudden increases and decreases in gas consumption.

Higher prices and greater volatility have brought increased attention to risk management techniques that can help prevent sudden and temporary spikes from raising residential heating bills. LDCs are starting to sign more long-term (12 months or longer) supply contracts and use futures contracts as a financial hedge, but they are still wary of doing so, lest prices move lower and regulators rule such contracts imprudent. After the relatively mild winter of 2001–02, which followed the record high prices reached the previous winter, many gas utilities were forced to explain why they had hedged their fuel cost at higher prices.

Demand forecasts increased

In its *Annual Energy Outlook 2008*, EIA predicted that annual electric power demand would remain relatively steady until its forecast for 6.7 Tcf in 2016, before gradually declining to 5.0 Tcf in 2030. Additionally, it predicted that annual industrial demand would climb to and remain at close to 7.0 Tcf. This led to a rising total annual demand forecast that rose from 22.9 Tcf in 2007 to 23.8 Tcf in 2016, before retreating steadily back to 22.7 Tcf in 2030.

In the *Annual Energy Outlook 2010*, the EIA forecasts electric power usage to fall to 4.8 Tcf in 2014, before climbing steadily back to roughly 7.4 Tcf in 2035. It expects annual industrial demand to continue falling to 6.0 Tcf in 2010, before recovering to the 7.0 Tcf in 2020. Then it sees industrial demand falling slowly back to 6.7 Tcf in 2035. EIA has also lowered its long-term demand forecasts for residential and commercial consumption. Due to the higher electric power demand and relatively steady demand in other areas, total demand is now expected to decline to 21.3 Tcf in 2014 from 22.6 Tcf in 2009, before climbing gradually to 24.9 Tcf in 2035.

Production to start rising?

EIA also made a dramatic change to its long-term domestic dry gas production forecasts. In its *Annual Energy Outlook 2008*, it predicted that production would rise gradually from 19.0 Tcf in 2007, reaching a plateau of 20.0 Tcf in 2021 and 2022, before gradually declining to 19.4 Tcf (85.5% of forecast total consumption) in 2030. In its *Annual Energy Outlook 2010*, it expects domestic production to recede to about 18.9 Tcf in 2013 and 2014, before rising to 23.3 Tcf (93.6% of forecast total consumption) in 2035. Should this dramatic increase in domestic production occur, then it is likely that natural gas imports would fall.

Imports to start declining?

US natural gas utilities have been relying increasingly on imported natural gas to meet growth in demand, a trend that is projected to loose importance in the years ahead. Since the early 1970s, when long-term growth in US natural gas production ended, imports—mostly from Canada, but also in the form of liquefied natural gas (LNG) from Africa and the Caribbean—have increased steadily, both in overall terms and as a percentage of US supply. Since 1973, net imports of natural gas have more than tripled in volume, growing by a cumulative average annual rate of about 3.6%. In 1973, net import volumes were 4.7% of total gas consumption. Imports peaked at 19.9% of total consumption in 2007, before falling to 16.4% of total consumption in 2009, likely due to the weak economy.

In its *Annual Energy Outlook 2008*, the EIA estimated that net imported natural gas would represent about 16.9% of US gas consumption in 2009, but shrink to 14.0% by 2030. However, in the *Annual Energy Outlook 2010* forecast, EIA now believes that net imports peaked in 2007, considering that it has changed its demand forecasts. At this point, the EIA sees net imports falling to 10.9% of total consumption by 2014 and then rising temporarily to 11.7% of consumption by 2017, before continuing its fall to 5.9% of total consumption by 2035.

While oil imports can easily be increased to accommodate rising demand, the same is not true for natural gas. Transportation is a major cost component of natural gas, whereas it is generally incidental to the cost of oil. As a result, the favored source of gas is domestic production. However, transportation of liquefied natural gas has made natural gas transportation far more economical than in the past.

Canadian import growth slowing

During the period from 1987 until 1997, increased imports from Canada served to fill most of the supply gap left by stagnating US production, rising at a compound average growth rate of 11.3% versus compound average growth of 1.3% for production. Imports from Canada rose every year from 1987 to 2002 and accounted for about 16% of total US consumption in 2007.

However, Canadian import growth slowed to a cumulative average growth rate of 2.7% for the period from 1997 to 2007, and fell 5.1% in 2008 and 9.0% in 2009. Canadian imports in 2009 were at their lowest level since 1998. Notwithstanding the falling imports in 2008 and 2009, likely related to falling prices, the weak economy and high storage levels, growth in Canadian domestic demand is beginning to erode the nation's export capacity; in 2003, gross natural gas exports to the United States fell by 9.2%, the first annual decline since 1986. Imports rose again in 2004 and in 2005, but did not regain the level reached in 2002. In 2006, imports from Canada declined 3.0% from 2005, as less natural gas was available for export, despite a slight rise in production. In 2007, levels rose 5.4%, approaching the imports seen in 2002.

As is the case in the United States, most of Canada's gas fields are mature. Forecasts show that production growth in Canada will fail to keep pace with higher consumption in the decades ahead, leaving less gas available to export.

According to Canada's National Energy Board (NEB), 76% of Canada's 2009 natural gas production came from Alberta, where there is growing local demand for natural gas to power development of the massive oil sands deposit. (In this process, natural gas is used to make steam, which is pumped underground to soften the heavy oil deposits so they can be recovered.) The NEB said in May 2009 that oil sands development consumed 1.1 billion cubic feet (Bcf) of natural gas per day in 2007—6.3% of Canada's total gas production in 2007 (the latest available data). In March 2010, the NEB said it expects development of the oil sands to consume between 1.4 Bcf/d and 1.6 Bcf/d by 2015. Project developers continue to look for alternative fuels, according to the NEB, such as bitumen gasification. In its *International Energy Outlook 2009*, the EIA estimated that by 2030 22% of Canada's natural gas consumption would be used in oil sands production, compared with 12% in 2006 (date cited by the EIA), thus diverting significant amounts of natural gas that might otherwise have been imported to the US market.

The EIA projects that these factors will reduce the net amount of natural gas imported by pipeline by a compound average rate of 6.3% per year from 2009 to 2024. In 2025, the EIA expects pipeline imports to rise slightly until 2031 and then begin declining at a 9.4% annual pace until 2035.

LNG EXPANSION UNDERWAY

Despite the long-term EIA forecasts for higher supply, and lower LNG needs, LNG facilities already under construction continue to be built. In the recent past, LNG facilities had been able to contract their capacity for decades. This meant that after the facility was built, the owner/operator of the facility would get paid whether or not any LNG was processed back into natural gas. The new EIA forecasts represent a major shift in its outlook, in our view, and if the economy has a strong recovery, the new forecasts might have to be revised to incorporate higher-than-expected economic activity.

With older forecasts showing that Canadian exports were unlikely to meet growing demands for US gas consumption, many companies determined that they could meet the demand imbalance by increasing imports of LNG by tanker. Many companies—ranging from holding companies that own LDCs to energy giants—were vying to take part in the growing LNG import industry. So far, most LNG plants that have been built or are under construction in North America have multi-decade contracts for a majority of the output from the plants.

The US imported a record 771 Bcf of LNG in 2007, which was 32% higher than the 584 Bcf received in 2006, 22% higher than the 631 Bcf in 2005, and 18% higher than the prior peak of 652 Bcf in 2004. However, LNG imports in 2008 were down 54% from year-earlier levels to 352 Bcf, seemingly ending the upward trend, but imports increased to 452 Bcf in 2009. LNG imports year to date through March 2010 were up about 61% and 84%, respectively, from the same periods in 2009 and 2008. The EIA believes that volumes may be even stronger for the remainder of the year, and projects a 94% rise in total volumes to 850 Bcf imported for 2010, helped by new LNG supply terminals scheduled to open.

Although global liquefaction capacity has increased considerably since 2005—as the result of capacity additions in Egypt, Trinidad and Tobago, Nigeria, Qatar, and Yemen among other countries—maintenance delays and lack of available feedstock gas caused LNG production to grow at a lower rate, according to the EIA. In recent years, there has also been strong demand for LNG in other countries, including Spain, France, Belgium, and the United Kingdom. LNG traders with options to deliver to multiple destinations found higher prices and more attractive markets in Europe and Asia in 2008 than in the US. However, EIA says that limited natural gas storage in those countries should allow the US to attract cargoes during the storage injection season (typically April through September) and that new liquefaction capacity may only have the opportunity to go to the US.

The EIA predicts that LNG imports to the United States will almost double between 2009 and 2012, but will then climb more slowly to a 1.5 Tcf peak in 2021, according to its *Annual Energy Outlook 2010*. According to a March 2008 report from Platts (which, like Standard & Poor's, is a unit of The McGraw-Hill Companies), the global regasification-to-liquefaction ratio is expected to rise to 3.22 in 2013 from 1.76 as of the date of the report. This suggests that there will be a lot of competition for cargoes of LNG.

US LNG infrastructure growing

Dozens of new projects to increase LNG supplies to the United States through expanded import infrastructure have been proposed. Some are already underway. As of June 4, 2010, nine LNG import terminals with a combined sendout capacity of 14.8 Bcf/d, or 5.4 Tcf annually, were operating in the US.

NORTH AMERICAN LNG TERMINALS

OWNER	LOCATION	CAPACITY (BCF/DAY)
CONSTRUCTED		
Cheniere Energy Inc.	Sabine, LA	4.00
Southern Union Co.	Lake Charles, LA	2.10
Dominion	Cove Point, MD	1.80
Sempra Energy	Hackberry, LA	1.80
Cheniere Energy Inc., private investor group	Freeport, TX	1.55
El Paso Corp., Southern LNG	Elba Island, GA	1.20
Suez LNG North America	Everett, MA	1.04
Sempra Energy	Baja California	1.00
Irving Oil, Repsol	St. John, New Brunswick	1.00
Excelerate Energy	offshore Boston	0.80
Shell Gas B.V., Total SA, Mitsui & Co. Ltd.	Altamira, Tamulipas	0.70
Excelerate Energy	Gulf of Mexico	0.50
UNDER CONSTRUCTION		
ExxonMobil	Sabine, TX	2.00
El Paso Corp., Sonangol, private investors	Pascagoula, MS	1.30
El Paso Corp., Southern LNG	Elba Island, GA (expansion)	0.90
KMS GNL de Manzanillo	Manzanillo, MX	0.50
Suez LNG North America	offshore Boston	0.40
US – ONSHORE – APPROVED BY FERC		
Cheniere LNG	Cameron, LA	3.30
Sempra Energy	Port Arthur, TX	3.00
Cheniere LNG	Corpus Christi, TX	2.60
Cheniere Energy Inc., private investor group	Freeport, TX (expansion)	2.50
AES Corporation	Baltimore, MD	1.50
ChevronTexaco	Pascagoula, MS	1.30
Crown Landing LNG, BP plc	Logan Township, NJ	1.20
4Gas	Corpus Christi, TX	1.10
Occidental Energy Ventures	Corpus Christi, TX	1.00
Gulf Coast LNG Partners	Port Lavaca, TX	1.00
TransCanada/Shell	LI Sound, NY	1.00
Northern Star LNG	Bradwood, OR	1.00
Northern Star LNG	Coos Bay, OR	1.00
Sempra Energy	Hackberry, LA (expansion)	0.85
Hess LNG	Fall River, MA	0.80
US – OFFSHORE – APPROVED BY MARAD/COAST GUARD		
Chevron Corp.	offshore Lousiana	1.60
Port Dolphin Energy	offshore Florida	1.20
McMoRan	offshore Lousiana	1.00
MEXICIAN APPROVED TERMINALS		
Sempra Energy	Baja California, MX (expansion	1.50
CANADIAN APPROVED TERMINALS		
Enbridge, Gaz Met, Gaz de France	Quebec City, Quebec	0.5
TransCanada/PetroCanada	Rivière-du-Loup, Quebec	0.50

LNG-Liquefied natural gas. Bcf-Billion cubic feet.
Source: Federal Energy Regulatory Commission (FERC).

Additionally, there were two operating terminals in Mexico with a combined sendout capacity of 1.7 Bcf/d, or 0.6 Tcf annually, and one in Canada with a sendout capacity of 1.0 Bcf/d, or 0.4 Tcf annually.

Several new LNG import terminals are under construction and expected to begin receiving supplies in 2010 and 2011. The Federal Energy Regulatory Commission (FERC) has approved plans for a total of 17 new terminals and three expansion projects, with a combined capacity of approximately 27.9 Bcf/d. Of these approved projects, only two terminals and one expansion project with a combined capacity of 4.2 Bcf/d are currently under construction.

Four offshore terminals with a total capacity of 4.2 Bcf/d have been approved by the MARAD/Coast Guard authorities. (MARAD is the Maritime Administration, which operates as part of the US Department of Transportation.) One of these, with a capacity of 0.4 Bcf/d, is under construction. Mexican and Canadian officials have approved a total of three terminals and one expansion project with a capacity of 3.0 Bcf/d; only one project under construction in Mexico has a capacity of 0.5 Bcf/d. Applications for another three onshore terminals with a capacity of 3.2 Bcf/d are pending FERC review, and another three offshore LNG terminals with a capacity of 5.3 Bcf/d are pending review by MARAD/Coast Guard authorities. Two plants on the West Coast—one at Coos Bay, Oregon, and one offshore California—that had previously filed applications with FERC and MARAD/Coast Guard, respectively, appeared to have met their demise in early 2010.

Despite the large amount of existing, approved, and applied-for North American capacity (total of 60.5 Bcf/d), many of the LNG terminals that have been proposed are unlikely to be built. In fact, if they are not yet under construction, we believe they will not be built, at least for a long time. Unapproved United States plants face a host of obstacles beyond federal approval, including local opposition and lack of demand for so many projects. Approved projects face a lack of demand, especially if the EIA's new supply and demand forecasts prove anywhere close to being accurate.

With operating North American LNG capacity at 6.38 Tcf annually, and another 1.9 Tcf annually under construction, the amount of capacity available to the market far exceeds the peak demand forecast by EIA through 2030. Even if we assume that the capacity is only used during the four warmest months of the year (June through September), when demand is lowest in Europe and Asia, there would still be enough capacity to import 2.1 Tcf using existing plants and another 0.6 Tcf assuming plants under construction are placed into service. Two new North American LNG import terminals entered service in 2008 and two expansion projects entered service in 2009. Combined, these terminals added capacity of 6.8 Bcf/d.

◆ **Northeast Gateway Energy Bridge.** Excelerate Energy LLC's Northeast Gateway Energy Bridge Project, off the coast of Boston, entered service in April 2008. This project uses Energy Bridge Regasification Vessels, which have the onboard capability to convert LNG back to the gaseous state. The resulting natural gas is then pumped from the ship directly into a subsea pipeline, which in turn is connected to an onshore pipeline to deliver the gas to end users. The facility's capacity is 0.8 Bcf/d. Due to the portable nature of the regasification facilities, it is unlikely that any of the capacity is contracted.

◆ **Freeport LNG.** Freeport LNG entered commercial service in April 2008. Its limited partnership interests are owned 70% by private investors and 30% by Cheniere Energy, while its general partnership interests are 50%-owned each by private investors and by Conoco Phillips. The project has an initial capacity of 1.55 Bcf/d. Located in Quintana, Texas, the project was built near two large natural gas trading hubs, Katy and Houston Ship Channel. There is no information on whether the facility has contracted any of its output.

◆ **Energía Costa Azul.** Sempra Energy's Energía Costa Azul on Mexico's west coast entered commercial service on May 15, 2008. The project has an initial capacity of 1.0 Bcf/d and may be expanded by another 1.5 Bcf/d. The project will connect to Sempra Energy's Baja Norte pipeline, which has connections to pipelines in the US. The facility is fully contracted for 20 years to Shell International Gas Ltd. (50% of capacity; Shell is a subsidiary of Royal Dutch Shell plc), and BP Tangguh project (50%).

◆ **Sabine Pass.** Cheniere Energy's Sabine Pass entered commercial service on November 6, 2008. The project has capacity of 4.0 Bcf/d after a 1.4 Bcf/d expansion project entered service in July 2009. Located in Sabine, Louisiana, the project will have access to several major pipelines through various pipeline interconnections with the company's Creole Trail Pipeline. Total SA (25%), Chevron (25%) and Cheniere Marketing have contracted all of the output from the existing plant and the 1.4 Bcf/d expansion (discussed below).

◆ **Cove Point.** Dominion's Cove Point LNG expansion project in Cove Point, Maryland, was completed in late 2008 and entered service in March 2009. It added capacity of 0.8 Bcf/d, bringing the terminal's total capacity to 1.8 Bcf/d. New capacity is contracted to Statoil for 20 years. The original plant is fully contracted to StatoilHydro ASA, Shell International Gas Ltd., BP, and peaking customers for 20 years starting in 2003.

◆ **Canaport.** Located in St. John, New Brunswick, Canada, the Canaport LNG terminal started commercial operations in June 2009. Irving Oil Ltd. and Repsol YPF SA (Spain) have partnered to develop this project. Repsol will hold all of the capacity in the plant. This terminal can accommodate imports of up to 1.2 Bcf/d. In July 2007, Canada's National Energy Board approved the Emera Brunswick Pipeline, which will connect the Canaport terminal with northeastern US and Atlantic Canadian markets.

◆ **Cameron**. Sempra Energy's Cameron LNG project in Hackberry, Louisiana has a capacity of 1.5 Bcf/d. Commercial operations began in July 2009. The project is 65 miles from a pipeline junction that gives it access to 65% of the gas markets in the US. Eni SpA has contracted 40% of the plant's capacity. Sempra has a short-term contract to buy up to 240 Bcf in 50 cargoes to help fill the remaining capacity.

Four new North American LNG import terminals and one expansion project with a combined capacity of 5.1 Bcf/d are scheduled to come online through 2011 to help serve the strong demand for natural gas in the northeastern US. According to the latest available numbers (June 2010), 11 northeastern states accounted for approximately 15.3% of total and 23.0% of residential natural gas consumption in 2008.

◆ **Neptune.** Suez Energy North America Inc.'s Neptune Project is scheduled to be commissioned in early 2010. This project, located close to the Northeast Gateway Energy Bridge Project, will deliver LNG imports from specially designed ships that will regasify the LNG through a subsea pipeline. The Neptune Project is designed to provide 0.4 Bcf/d. Due to the portable nature of the regasification facilities, it is unlikely that any of the capacity is contracted. On November 30, 2009, the first of two shuttle and regasification vessels designed to bring gas to the Neptune project, as well as other deepwater LNG ports, was delivered to Suez.

◆ **Golden Pass.** Golden Pass LNG project, owned by Qatar Petroleum (70%), ExxonMobil (17.6%) and Conoco Phillips (12.4%), in Sabine, Texas is expected to enter service in mid-2010 and have an initial capacity of 2.0 Bcf/d. LNG will be supplied by RasGas, owned by Qatar Petroleum (70%) and ExxonMobil (30%).

◆ **Elba Island.** El Paso Corp.'s Elba Island LNG expansion project in Georgia is expected to be completed in phases, with the first phase completed in mid-2010 and the second phase completed in 2012. The project should add capacity of 0.9 Bcf/d, bringing the terminal's total capacity up to 2.1 Bcf/d. The plant's existing capacity and the expansion's capacity have been contracted under long-term contracts to BG Group and Shell International Gas Ltd.

◆ **Gulf.** The Gulf LNG project, owned by El Paso (50%), private investors (30%), and Sonangol USA Co. (20%; Sonangol is a unit of Sonangol UEE), in Pascagoula, Mississippi, is expected to be completed in 2011 and have an initial capacity of 1.3 Bcf/d. The project has an existing pipeline infrastructure with access to markets in southeast Texas and other parts of the US. The plant is fully contracted for 20 years from the date it enters service.

◆ **Manzanillo, Mexico.** The Manzanillo LNG project, owned by KMS GNL de Manzanillo, in Manzanillo, Mexico, is expected to be completed in 2011 and have an initial capacity of 0.5 Bcf/d. The project is expected to serve the Port of Manzanillo, a gas-fired power plant, as well as a bidirectional pipeline to be built between Manzanillo and Guadalajara.

Due to a previously widespread view that LNG imports were of increasing importance, on June 5, 2007, MARAD signed an agreement designed to allow state maritime academies and labor-based training facilities to develop liquefied gas training standards for US mariners. These training standards will be used to expand existing programs and to develop new programs to provide entry-level mariners with employment in the LNG industry, and to facilitate the retraining and/or recertifying of current mariners to permit their transition into LNG-related service.

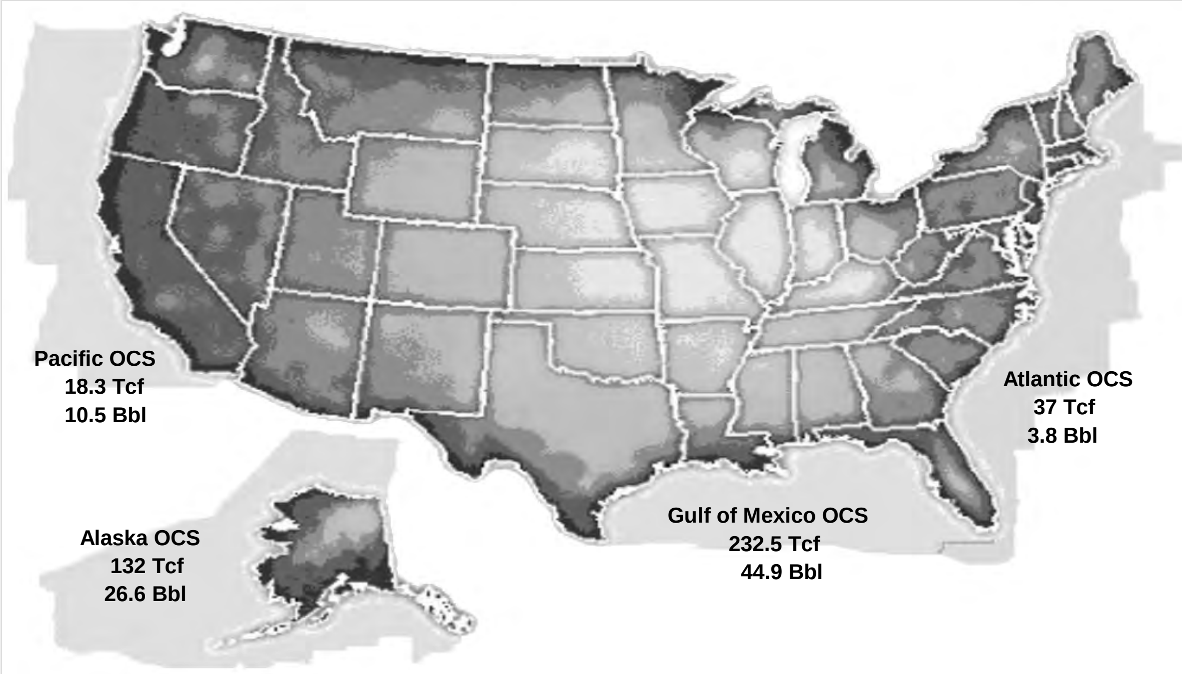
OTHER NEW SOURCES OF GAS SUPPLY

As LNG's share of US natural gas imports may change, so too can the composition of domestic onshore gas production. LDCs must consider this fact as they formulate their views on future market conditions and prices. With gas output from traditional oil and gas wells declining, producers are increasing their investment in new, "unconventional" sources of supply: gas found in oil shale, coal beds, and "tight sands" gas—geologic formations that hold low concentrations of gas. These new sources have somewhat different production characteristics than traditional wells, as each well produces lower daily volumes but has a longer lifetime.

According to the *Annual Energy Outlook 2010 (Early Release)*, unconventional sources of gas accounted for 16.8% of total US gas production in 2008. That share will grow to 34% by 2035, according to the EIA. The EIA assumes in its reference case that an Alaskan pipeline link will begin operations in 2023 and is expected to expand natural gas production in Alaska nearly sevenfold by 2035. If the pipeline does not get built, EIA expects that additional production of gas from unconventional sources and additional LNG imports will fill the gap.

Even including the new sources, total US dry gas production is expected to increase by an important but still anemic average annual rate of 0.5% between 2009 and 2035. This low growth rate has led to calls from a

OFFSHORE POTENTIAL



OCS-Outer continental shelf. Tcf-Trillion cubic feet. Bbl-Billions of barrels.
Source: American Gas Association, used with permission.

variety of sources—including both energy-producing and energy-consuming groups—for the United States to open up more of the country for exploration and production. However, we believe that this push will be unsuccessful in the near future due to the record oil spill in the Gulf.

PIPELINE CAPACITY EXPANDING…

Pipeline capacity for natural gas is being expanded in part to bring gas to the northeastern US. Some of the new pipelines will allow expected LNG imports to move from LNG terminals to major gas pipelines, while others should help to move new gas discoveries in the western and mid-continent US supply regions to distributors and end users in the Northeast and on the West Coast. Completion of these pipelines could help to reduce city-gate price volatility in the Northeast.

New pipeline projects approved by FERC include 2,782 miles of new pipeline in 2007, 2,084 in 2008, and 1,133 in 2009. Of the 35 projects that were approved in 2007, only 11 were longer than 100 miles. In 2008, nine projects were approved, of which five were in excess of 100 miles. In 2009, only seven projects were approved, with half of them over 100 miles. Shorter projects include smaller new pipeline projects, expansions, extensions, interconnections, and laterals to reach new LNG or storage facilities or other pipelines. However, through June 7, 2010, only six projects (1,133 miles) were approved, with five over 100 miles. FERC said that there were an additional 3,745 miles of pipeline projects "on the horizon" as of May 2010. Some major pipeline projects (over 500 miles) are detailed below.

◆ **Rockies Express Pipeline**. Jointly owned by Kinder Morgan Energy Partners, Sempra Energy, and Conoco Phillips, the Rockies Express Pipeline is a 1,679-mile, 1.8 Bcf/d natural gas pipeline system that runs from Rio Blanco County, Colorado, to Monroe County, Ohio. Rockies Express–West (713 miles) was approved in April 2007 and was placed in service on May 20, 2008. Rockies Express–East (638 miles) was approved in May 2008 and entered full service in November 2009 after several delays related to weather. The Entrega (328 miles) segment of the Rockies Express Pipeline was fully operational by February 2007.

◆ **Midcontinent Express Pipeline**. Jointly owned by Kinder Morgan Energy Partners and Energy Transfer Partners, the Midcontinent Express Pipeline is a 507-mile, 1.5 Bcf/d natural gas pipeline system that runs from the southeast corner of Oklahoma across northeast Texas, northern Louisiana, and central Mississippi into Alabama. The pipeline was approved in July 2008 and entered full service in August 2009.

…but more slowly

At least three other 500-mile–plus pipelines were announced in 2007 or 2008. However, two of these projects were either cancelled or postponed due to a drop in the amount of natural gas expected to be flowing out of the Rockies region.

◆ **Ruby Pipeline**. This project, owned jointly by El Paso and Global Infrastructure Partners, is a 678-mile, 1.5 Bcf/d natural gas pipeline system that starts at the Opal Hub in Wyoming and terminates at the Malin, Oregon, interconnect near California's northern border. The FERC application was filed on January 27, 2009, and approved on April 5, 2010. Construction was expected to begin shortly, with the pipeline scheduled to be placed in service in March 2011.

◆ **Sunstone Pipeline**. Jointly owned by Williams Cos., TransCanada, and Sempra Energy, and announced in 2008, the Sunstone Pipeline project has been suspended as the project partners reevaluate the project's timing and scope. The project is a 585-mile, 1.2 Bcf/d natural gas pipeline system that runs from the Opal Hub in Wyoming to Stanfield, Oregon. The project had originally been expected to be completed in 2010.

◆ **Bison/Pathfinder Pipelines**. TransCanada Corp.'s Pathfinder project—a 673-mile, 1.6 Bcf/d natural gas pipeline system running from Meeker, Colorado, to an interconnection in North Dakota with the Northern Border Pipeline Co. (NBPL) system—was effectively cancelled in 2008 when it was merged by the company with its Bison project. The smaller Bison project, with a capacity of 0.5 Bcf/d, will extend 302 miles from Gillette, Wyoming, into North Dakota, where it will connect with the NBPL, which can carry gas to the Midwest. TransCanada expects the Bison project, which received FERC approval on April 9, 2010, to commence operations in November 2010.

CUSTOMER CHOICE PROGRAMS FALL FLAT

The drive to introduce competition to the utility industry during the 1990s led several states to order their LDCs to "unbundle" (formally separate) their supply function from their distribution function in order to allow other independent suppliers to enter the market and retail competition to develop. The idea was that customers would end up paying less for their natural gas supply if they were allowed to shop among different suppliers for the best price, rather than simply buying from the distribution utility at the utility's cost. While the idea seemed logical in theory, in many cases it is clear that, at the residential level, retail unbundling has failed to generate the competition and related advantages that regulators expected.

Except for the largest gas consumers—industrial companies and power generators for whom natural gas is a major expense—customer interest in switching suppliers has been disappointingly low. Even more discouraging for the proponents of retail-level gas supply competition, the number of active retail suppliers competing for customers had been shrinking through 2005, rather than expanding as they had expected. However, in 2009, the number of active suppliers increased meaningfully for the third year in a row, seemingly reversing this trend.

Across the US, about 35 million gas customers in 21 states and the District of Columbia—just over half the US total—are able to switch suppliers, but only 14.7% of those eligible for customer choice programs were participating in the programs in 2009, according to the latest data from the EIA. Just three states—Georgia, Ohio, and New York—now account for 74% of the customers who have switched suppliers.

The number of gas customers buying their gas from a source other than their LDC in 2006, 2007, 2008, and 2009, increased by 327,000, 459,000, 49,000, and 445,000, respectively. During that period, gains in just four states represented 91% of the total increase. In Ohio, switching participation increased from 36.3% to 58.2% for a total increase of 574,000 (49% of the period's total gain). In New York, switching participation increased from 7.8% to 16.0% for a total increase of 359,000 (31% of the period's total gain). Switching participation increased in Illinois and Michigan, and accounted for the remaining 20%. While switching in these four states and, to a lesser degree, in five other states, appeared to be gaining ground, the remainder of the states did not show meaningful increases in switching activity between 2005 and 2009. In Maryland, it should be noted that while switching levels dropped 9.3% in 2006 and 4.0% in 2007, levels have rebounded by 2.4% in 2008 and 9.1% in 2009. The number of customers that switched suppliers totaled 5.1 million at year-end 2009.

State programs to allow and encourage retail supply competition have fallen into disarray. Just three states (New York, New Jersey, and Pennsylvania) and Washington, D.C., now have active programs in which all residents are eligible, by law, to choose their supplier. Participation was less than 10% in each area, except New York, which broke the barrier in 2007. Four other states (New Mexico, California, West Virginia, and Massachusetts) also have legislated 100% eligibility, but their programs are inactive, and participation rates are all less than 1% of those that were eligible. Finally, six states (Georgia, Illinois, Maryland, Michigan, Ohio, and Virginia) allow more than 50% of their customers to switch; of these states, only Georgia (100% of eligible customers), Ohio (58.2%), Maryland (12.0%), and Michigan (10.8%) had switching levels above 10%.

COMPANIES CHANGE COURSE

In recent years, several utility companies have changed course on ownership of nonutility businesses. In many cases, these businesses had high capital requirements due to required collateral postings. Some have sold these businesses outright, one scaled back its operations while trying to sell, and one placed its business into a joint venture in an effort to reduce risk and refocus the companies on their core equity businesses. In most cases, the companies have used the cash from asset sales for share repurchases and dividend hikes. In some cases, companies have paid down debt, but in others, the business risk of the overall company has dropped, allowing them to increase their debt load.

Merger activity stalls…

There was very little significant merger and acquisition activity among key gas utility companies in 2007, 2008, and 2009. In 2007, some deals took longer than expected to close, while others were cancelled. In addition, companies divested E&P businesses in 2007. In 2008, only two significant transactions took shape. Activity has likely slowed due to stock price weakness (companies often use stock as currency in acquisitions) at the same time that companies cut capital spending plans, borrowing costs increased, and access to capital became more difficult.

Should gas prices return and remain at high levels, we think that a resumption of industry consolidation could occur. For a utility with no or very small non-utility businesses, we believe that growth through merger savings could be their only viable option to achieve higher-than-industry-average earnings per share (EPS) growth. Recent moves by international owners of US utilities to exit the US has lead to several recent deals. There also have been some discussions of spinning off utility businesses from companies whose unregulated E&P businesses now dwarf their utility operations.

On October 1, 2008, Sempra Energy completed its purchase of EnergySouth for $510 million in cash. In addition to a small distribution utility in Alabama (93,000 customers), Sempra gained two large, high-cycle underground natural gas storage facilities that, when fully developed, will have capacity of 57 Bcf. At the time of the deal's closing, only 11.4 Bcf of storage was operational; the remainder is slated to come into service during 2010 and beyond.

A $970 million deal in 2007 for the sale of two natural gas utilities owned by Dominion Resources was cancelled in 2008 after resistance from the Federal Trade Commission on antitrust grounds. However, on July 2, 2008, a private equity fund agreed to purchase the same assets for $910 million. However, regulatory issues forced the sale of one of the utilities to be cancelled. The other sale was completed in February 2010 for $737 million.

Are cross-border deals the shape of things to come?

In August 2007, National Grid PLC acquired KeySpan (with 2.6 million gas customers in New York, Massachusetts, and New Hampshire) for $7.3 billion in cash. In September 2008, Spanish firm Iberdrola SA purchased Energy East Corp. (with 1.8 million electricity customers and 900,000 natural gas customers in New York, Maine, and Connecticut) for $4.5 billion. These deals are of particular interest because they may augur similar deals in which large foreign utility companies seek to diversify through the acquisition of US utility businesses. Iberdrola has stated that it viewed the US as one of its best opportunities for growth, but we believe the company is more interested in electric companies than gas, which has led the company to sell the three gas utilities that were acquired in its Energy East acquisition.

In the first of two recent international deals, on April 28, 2010, PPL Corp. agreed to purchase Louisville Gas and Electric Co. and another electric utility from E.ON's US operations for an effective price of $7.2 billion. E.ON decided on the sale in order to shore up its balance sheet. Approvals are required from state regulators in Kentucky, Virginia, and Tennessee, and the FERC. PPL expected the transaction to close by the end of 2010.

On May 25, 2010, UIL Holdings agreed to acquire Southern Connecticut Gas Co., Connecticut Natural Gas Corp., and Berkshire Gas Co. for about $1.3 billion in cash from Iberdrola SA. UIL expected the deal to close in the first quarter of 2011. Approvals are required by the FERC, the Connecticut Department of Public Utility Control, and the Massachusetts Department of Public Utilities.

Standard & Poor's believes that cross-border deals are not likely in the near future due to the declining value of the Euro combined with a challenging economic environment. However, we believe more international utility acquisitions will be announced in the event of an economic recovery. We also see a longer-term potential for a decline in the value of the US dollar against other currencies if European countries are able to implement austerity measures while maintaining economic health. Foreign acquisitions have the potential to spur domestic consolidation: local companies may combine to avoid becoming takeover targets for larger foreign utilities.

LDCs slow diversification efforts

Because their returns are regulated and their industry mature, natural gas distribution utilities traditionally have had severely limited growth prospects. Historically, earnings for US LDCs have grown with the help of only population growth and rate increases. As a result, share prices have tended to lag shifts in the larger market.

Until the 1990s, there was little that executives of LDC companies could do to raise their growth rates and boost shareholder returns, and their shares were usually held for current income rather than growth. That changed, however, during the latter half of that decade, when regulatory reforms began allowing LDCs to form holding companies that could invest in other, unrelated businesses offering stronger growth prospects—accompanied by greater risks.

For several years, gas and power utilities embarked on a campaign of often-indiscriminate spending, negotiating mergers, building and buying new unregulated, "merchant energy" power-generation assets, acquiring overseas operations, and establishing (and funding) trading desks, as well as expanding into novel areas such as telecommunications, construction, and even healthcare. This strategy of diversification proved to be far less profitable than originally envisioned, however, and many companies were forced to sell or even abandon recently purchased assets in order to reduce their crippling debt loads.

The frenzied corporate realignment of the 1990s came to a halt in 2001, when the bankruptcy of Enron Corp. and the power crisis in California undermined investor confidence in the benefits of asset diversification. During 1998 and 1999, a total of 18 mergers involving US LDCs were announced; between 2000 and 2004, there were only six.

This wave of activity changed the face of the natural gas industry, but no dominant business model has emerged. Many gas distribution companies are owned by large multi-industry companies or multi-utility companies, such as Dominion Resources, Sempra Energy, Questar Gas, Equitable Resources, and MDU Resources Group. These companies have a broadly diversified asset base, which includes regulated gas and electricity distribution utilities (domestic and foreign), unregulated power generation assets, exploration and production operations, long-distance pipelines and storage, LNG import terminals, and even construction materials supply. Another group—which includes Nicor Inc., AGL Resources, and WGL Holdings Inc.—is more gas-focused, combining regulated gas distribution utilities with long-distance pipelines and unregulated businesses of varying sizes.

In recent years, several companies have exited or are in the process of exiting some of their nonutility businesses in an effort to refocus on their utility operations. We believe these moves indicate a realization among executives that many of these businesses were using capital that could otherwise be redeployed within the companies for growth in the utility businesses or to fund dividends and/or share repurchases.

In April 2010, Questar Corp. announced a move similar to Duke Energy Corp.'s 2007 spin-off of its Field Services unit into Spectra Energy Corp. Questar said it planned to separate its Questar E&P Company, Questar Gas Management, and Questar Energy Trading units into a separate publicly traded company, but to retain its utility business and Wexpro (an E&P company that serves its utility). When announced, the company expected the transaction to close in the second half of 2010.

In 2007, Dominion Resources Inc. completed a corporate restructuring that included the divestiture of its non-Appalachian exploration and production (E&P) assets for roughly $13.9 billion in several transactions. The company is using the proceeds for share repurchases, debt reduction, and general corporate purposes. Similarly, in August 2007, Integrys Energy Group Inc. sold Peoples Energy Production Co., an oil and natural gas exploration business included in its acquisition of Peoples Energy, to El Paso Corp. for $875 million. Integrys also announced in late 2008 that it was planning to sell or shut down its nonutility energy services business. The company subsequently decided to retain a selected portion of its Energy Services retail natural gas and electric marketing businesses with a focus on the northeastern quadrant of the US. On April 1, 2008, Sempra Energy, in a risk-reducing move, placed its commodity trading into a joint venture with a partner that had a stronger credit profile, so that it could use about $1 billion in returned collateral to repurchase shares.

HOW THE INDUSTRY OPERATES

Natural gas is a colorless, odorless fuel composed primarily of methane and ethane. It burns more cleanly than many other fossil fuels—emitting less carbon dioxide than coal or oil, and little sulfur or particulates—making it one of the most popular sources of energy today. Natural gas provided about 24% of the US energy supply in 2008, a share that is expected to drop to 22% by 2030, according to the Energy Information Administration (EIA), part of the US Department of Energy.

THE NATURAL GAS SUPPLY CHAIN

The natural gas supply chain comprises three distinct segments: upstream, midstream, and downstream. Parts of the chain include wells, processing plants, pipelines, liquefied natural gas (LNG) facilities, storage facilities, and distribution facilities.

E&P: the upstream segment

Exploration and production (E&P) companies search for gas underground and bring it to the surface through wells. The supply of natural gas in the United States comes chiefly from domestic E&P operations. Domestic dry gas production accounted for 88.7%, or 21.0 trillion cubic feet (Tcf), of total US supply in 2009, according to the EIA, while net imports via pipeline contributed 9.6%, or 2.3 Tcf. Net LNG imports made up the remaining 1.8%.

Within the US, natural gas is produced in 32 different states, but just seven (Texas, Alaska, Wyoming, Oklahoma, New Mexico, Louisiana, and Colorado) accounted for 77.1% of total output in 2008, according to the latest available data (May 2010) from the EIA. The federally administered Gulf of Mexico Outer Continental Shelf (OCS) region provided a further 9.1% of total production. In addition to supplying the domestic market, US natural gas producers also export small amounts of gas to Canada and Mexico via pipeline, and to Japan and Mexico as LNG.

Raw gas from underground reservoirs is moved through a series of feeder (gas gathering) pipes to processing plants that remove impurities and natural gas liquids (NGLs—such as propane or butane). The propane and butane can be stored and sold on site or moved through NGL pipelines to other locations. The almost pure methane gas that results—known as "pipeline gas"—is then sent to long-distance transmission pipelines.

Pipelines: the midstream

The midstream segment comprises interstate pipeline, or "transmission," companies, which build and operate pipelines to transport gas from producing regions to demand centers. Transmission companies are regulated by the Federal Energy Regulatory Commission (FERC), which has jurisdiction over interstate commerce in natural gas. The EIA estimated there were 217,306 miles of interstate pipelines in the lower 48 states at the end of 2008 (latest available data as of May 2010) and an additional 88,648 miles of intrastate pipelines.

Attached to the pipeline systems are many natural gas storage facilities, which are used to store gas during periods of nonpeak demand in order to be able to maintain supply during peak demand times. At the end of 2008 (latest available data as of May 2010), there were 401 storage facilities with 8.5 Tcf of total storage capacity, or 4.2 Tcf of working gas capacity, according to the EIA. Working gas capacity is total gas minus base gas capacity. Base gas capacity is an amount of gas needed to maintain adequate pressure in a storage reservoir during the withdraw season.

Although US gas storage capacity is located in 30 states, eight states (Michigan, Illinois, Pennsylvania, Texas, Louisiana, Ohio, West Virginia, and California) account for more than two-thirds of the total. Numerous gas storage projects are in the works to accommodate increased gas usage and to improve reliability. The added storage capacity is likely to result in additional gas purchases during off-peak months to refill the storage fields in advance of the winter season, thus helping to smooth seasonal price fluctuations by increasing nonpeak demand and decreasing peak demand.

LNG terminals and ships: another piece of the midstream

LNG is simply gas that has been cooled to 260 degrees below zero on the Fahrenheit scale; at this temperature, it condenses into a liquid from a gas. Gas is condensed at liquefaction facilities in countries that export the gas. Once condensed, the liquid takes up about 1/600 the space of the gas at atmospheric pressure.

LNG is transported on specially made ships. Some of the liquefied gas stored on the ships is returned to a gaseous form and is used as fuel for the ship or its cooling system. At the end of its journey, the LNG is transferred to a regasification facility, where the gas is warmed (and thus returned to a gaseous state) and then either stored in storage facilities or put directly into gas pipelines for transportation to other markets.

In recent years, numerous LNG terminals (which include regasification facilities) have been proposed for construction. Many proposed for locations outside of the Gulf states have run into local opposition and may not be built. Several are under construction, however, and others are likely to be built.

International competition for LNG is strong, with the ships serving the highest-priced markets first. However, most LNG regasification facilities have long-term contracts that guarantee payment to the facilities' owners whether the facility is used or not.

LDCs: the downstream segment

Local distribution companies (LDCs) occupy the downstream segment of the gas industry, taking gas from interstate pipelines and distributing it to a broad range of customers, including residential, commercial, industrial, and power generation. They perform this service under a monopoly concession and are subject to rate regulation.

LDCs are sometimes run as stand-alone operations, but independent LDCs have become increasingly rare in recent years. Following regulatory reforms that eased restrictions on mergers by gas and other utilities, most LDCs are now owned by larger holding companies that also own other businesses, including other regulated gas and electric utilities, as well as unregulated businesses that may or may not be related to energy.

It is important to remember that LDCs perform two related, but distinct, services: the delivery of gas, as well as the procurement and sale of gas to the customer. LDCs deliver gas to customers through pipeline networks they build and maintain, and attempt to earn a profit for providing that service. In addition, they procure gas and sell it to customers at cost, a service for which no profit is earned. In both cases, the rates that they can charge are regulated by state officials, and LDCs have no guarantee that state regulators will allow them to fully recoup the cost of gas sold to customers.

REGULATION: A PART OF DOING BUSINESS

LDCs operate under monopolies that are granted by a state or municipality and cover a particular service area. State utility commissions regulate just about every aspect of an LDC's activities, including what it can charge for delivery and for gas supply. Often known as Public Utility Commissions (PUCs) or Public Service Commissions (PSCs), state regulators are responsible for ensuring the safe and reliable access to gas on an equitable basis and, in some cases, for promoting competition.

State utility commissions usually consist of a board of three or more members appointed by the state's governor and confirmed by the legislature. (In some states, utility commissioners are elected by popular vote.) The commissions often employ a large staff, including attorneys and accountants, to evaluate information filed by utilities regarding potential rate changes and to assist commissioners in making decisions. Utility commissions may regulate one or more natural gas utilities as well as other businesses, such as electric and water utilities, telecommunications providers, and cable television operators.

In addition to setting rates of service, a state utility commission issues regulations covering other important aspects of an LDC's operations. It oversees environmental performance, monitors the LDC's operations to ensure that it complies with relevant laws, and enforces universal service obligations. It has authority to approve or deny corporate mergers, the sale of facilities from one party to another, and even such financing activities as bond issues or intracompany fund transfers.

Ratemaking

The greatest power that state utility commissions hold over LDCs is the ability to set the rates LDCs are allowed to charge for delivery and for gas supply. As a practical matter, the delivery charge is the more complex to set, since it must allow the LDC to earn a profit. Gas supply charges, while not free of controversy, are more an issue of reimbursement, though disputes can and often do arise over whether a gas supply charge was prudently incurred. In 2007, most states created rate frameworks that seek to minimize disagreements and allow customer charges to more closely reflect volatile natural gas prices.

A natural gas utility's rates for its delivery service are mostly set on a "cost of service" basis; that is, rates are calculated to generate enough revenue for the utility to recover its operating costs and earn a fair return for shareholders. This makes the relationship between a utility and its regulatory commission an important determinant of both its current profitability and its long-term growth prospects.

In general, the ratemaking process begins with a request from the regulated utility for a change in rates when the current rate schedule expires. The process of deciding what rates a utility will be allowed to charge is known as a "rate case." In addition to the change in rates requested, there may be simultaneous negotiations between the company and the commission on any other issues that one or both sides want to address, such as customer complaints, infrastructure investment, environmental issues, or reliability problems.

The first step in the rate case is determining the cost to maintain and operate the distribution system as well as the cost of any capital improvements that are needed. This amount is calculated by totaling the company's operating and maintenance expenses, asset depreciation, and taxes over a hypothetical period known as a "test year" that has been normalized to eliminate any unusual or one-time incidents. The commission must decide whether to allow each expense item submitted by the LDC; if an item is denied, its cost must be borne by the utility's shareholders. Disputes often arise over whether a particular cost should or should not be reimbursed by ratepayers.

Setting a utility's rate of return

Once the utility's expenses have been determined, the utility's management and regulators must then negotiate an appropriate rate of return for the utility, a rate that will provide an adequate incentive for investors to own equity in the LDC and thus ensure it is adequately capitalized to provide acceptable service. Deciding what level of return the company should receive is often the most controversial part of the rate case—and a process that is as much art as it is science.

For investor-owned utilities, the return is usually calculated as the percentage of the utility's assets used to deliver service that is needed to cover the utility's cost of capital. Cost of capital is defined as the sum of the cost of debt service, preferred stock dividends, and a fair return for common stockholders. While the cost of debt service and preferred stock dividends is easy to establish, the appropriate return for common stockholders is more difficult to ascertain. Commissions use such methods as comparable company analysis, discounted cash flow, and risk premium analysis (such as the capital asset pricing model) to determine an appropriate return on common equity. In some instances, a utility commission may desire to set a rate of return that is not equivalent to the utility's cost of capital, as either a reward or punishment for management decisions and operating performance.

It is important to remember that in setting the rate of return, the utility commission does not guarantee that the LDC will actually earn that rate, but instead gives the LDC the opportunity to earn that rate. Sound management and operating skill are needed to achieve the allowed rate of return, and poor decisions can leave the realized rate of return significantly below the allowed rate.

Once the utility's full revenue requirement (costs, plus a fair return) has been identified, that sum must then be allocated among the different classes of gas consumer: industrial, residential, commercial, and power generators. Industrial rates tend to be the lowest, because industrial customers are high-volume users and are easier to service than residential accounts. Allocations can be controversial, since one customer group may argue that it is being forced to subsidize another.

After it has been determined how much each class of customer will pay in total, the structure of the charges is determined in a process known as "rate design." Rate designs vary considerably and can include fixed per-customer charges, minimum bills, charges per therm (a unit of heating value), or some combination of these.

Alternatives to cost-of-service ratemaking

Cost-of-service–based ratemaking has several important disadvantages when it comes to the incentives it offers for efficient utility performance. Just determining the actual cost of service is cumbersome, time-consuming, and adversarial, and is complicated by the fact that many investor-owned utilities operate more than one LDC—thus raising issues about what costs should be allocated to what operation. Furthermore, cost-of-service ratemaking provides a strong incentive for a utility to inflate the size of its asset base by so-called gold plating: overinvesting in assets that are either unnecessarily expensive or redundant, because the larger the rate base, the higher the return.

To counter this problem, some states have begun to experiment with incentive-based rates that seek to promote efficiency, either through rewards for the attainment of performance goals or through punishments for the failure to achieve expected standards. Various kinds of performance-based structures exist, each with unique advantages and disadvantages.

◆ **Regulatory lag**. One of the simplest ways to create more incentives for improved performance is known as "regulatory lag," or the extension of the minimum time between rate changes. This produces a strong incentive to cut costs, because utilities will keep 100% of any cost savings made during the period; they also would bear 100% of any additional costs incurred.

◆ **Price cap.** Another kind of incentive-based ratemaking formula is the price cap, in which the charge for distribution is set through a formula that adjusts the previous charge according to inflation (usually based on the consumer price index) and also according to expected gains in productivity. This has the effect of forcing a utility to make productivity gains—because prices already are calculated to reflect them. Further gains, however, would increase the utility's return, providing a strong incentive to increase productivity beyond the set target. The success of this formula depends on the correct setting of the expected productivity gain factor in determining future prices. A factor set too low would allow the utility to earn above-normal profits, while a factor set too high might prevent it from fully recovering its costs. Price caps are more common outside the United States.

◆ **Revenue cap.** An alternative to the price cap is the revenue cap, which can take the form either of an absolute revenue cap or a revenue-per-customer cap. With revenues fixed, profits will rise only if costs are cut.

◆ **Earnings sharing**. Another kind of incentive-based rate that has gained popularity in recent years is "earnings sharing." When regulators determine a utility's rate of return for a given period, the specified return is actually a target return that the rate schedule is designed to produce.

Because actual events may lead to a different return, regulators may set a band that is designated as an "allowed rate of return," which regulators view as an acceptable variation from the target. If actual returns fall below that band, the utility may be allowed to petition for a rate change. If returns are above the target band, the "excess" earnings are shared, in part or in whole, with customers in the form of future rebates. This protects the utility from unexpectedly low returns and lets customers benefit from improved efficiency.

Each of these alternatives has potential drawbacks, and studies examining alternative regulatory regimes have found it difficult to determine their overall effects. Because incentive-based rate designs do not offer a clear opportunity to enhance returns and usually entail some risk, some utilities have preferred to remain under traditional regulation.

Helping utilities to encourage efficiency

Some states have acknowledged that increasing efficiency in appliances that use natural gas has led to declining consumption of gas per customer over time. As a result, the fixed-cost component of a utility's expenses has been increasing over time relative to its revenues. Since rates typically are largely tied to utilities' throughput, utilities have been having a harder time recovering the fixed investments that they make in distribution pipeline and service connections. Therefore, a utility with rates mostly tied to variable usage is averse to helping customers to conserve gas.

As a result, some states have implemented revenue-decoupling mechanisms that increase the fixed charges on customers' bills. In exchange for this concession, utilities that have revenue decoupling mechanisms in their rates have agreed to invest in programs that may give rebates to customers for installing more efficient, but more expensive appliances, thus encouraging conservation. The higher fixed charges on customers' bills are designed to allow utilities with this rate mechanism to collect enough for maintenance costs, new connections, and a fair return on fixed plant investment.

WEATHER INFLUENCES EARNINGS

With delivery rates typically tied to the volume of gas delivered, and costs that are mostly fixed, LDCs' earnings traditionally have been highly sensitive to changes in the weather. Colder-than-normal winter weather has the effect of increasing volume (and therefore, sales), while warmer-than-normal weather can cut volumes significantly, eroding profitability.

In setting rates, regulators assume a particular level of demand and gas distribution volumes. Unusual weather patterns can make this assumption either too high, leaving the utility with a revenue shortfall, or too low, giving the utility a revenue windfall. To smooth these peaks and valleys, many states have started to include "weather normalization" clauses that serve to reduce weather-related effects and redress earnings volatility. A shift in weather patterns that causes a greater- or less-than-expected number of degree days (a measure of the variation of the mean daily temperature from a reference temperature) triggers a surcharge (in the case of unusually warm weather) or credit (when the weather is cold), applied to customer bills to offset the effect of weather. A more recent option for utilities seeking to minimize the effects of weather on earnings is to use weather-based financial derivatives.

Because revenues are tied to delivered volumes, LDCs have a strong incentive to discourage energy efficiency and conservation, something state regulators would like to change as natural gas prices rise. In recent years in some states, a new "conservation tariff" has been used that decouples an LDC's revenue from its delivery volumes by protecting profit margins in the event that delivery volumes decline. This is accomplished by mechanisms that change the price of gas delivered according to actual volumes delivered, or by "deferral accounts" that keep track of the impact of conservation measures and provide for deferred collections or refunds at set times.

MANAGING GAS SUPPLY

In addition to maintaining a pipeline network, an LDC is responsible for managing the supply of gas moving through its network, in order to maintain adequate pressure in the system and meet the full requirements of customers during times of peak demand. LDCs are responsible for delivering gas that customers have purchased from an independent competitive supplier, as well as supplying gas to customers that are either unable to choose a competitive supplier or fail to do so. When supplying gas directly to customers, an LDC must purchase the gas itself, as well as pay for transportation of the gas to the LDC's network (and possibly for storage as well).

Deregulation creates choices

Before 1984, when deregulation of the interstate pipeline industry first began, LDCs were forced to buy their gas directly from the transmission pipeline company that served their area as part of a package that included both the gas itself and pipeline transportation to the LDC's city gate. These purchases were made under long-term contracts that obliged the LDC to pay for a certain amount of gas even if the gas was not needed.

In 1984, FERC's Order 380 freed LDCs of those "take-or-pay" contractual obligations, thereby allowing them to start buying gas directly from producers on the spot market, once their take-or-pay obligations were satisfied. The FERC went on to issue a series of orders dismantling pipeline regulations. This process culminated in 1992 with Order 636, known as "The Restructuring Rule," which required pipelines to offer transportation service as a separate service on terms equal to those given customers buying gas from the pipeline.

Since that time, a wholesale market for natural gas in the United States has developed that allows LDCs to purchase gas on a variety of terms and from a variety of different sources. A new class of independent gas marketer sprang up to compete with gas producers and pipelines by offering different products that allow LDCs to create their own supply portfolios, reflecting each LDC's individual circumstances and needs. LDCs have taken advantage of the shift to diversify their sources of supply away from pipeline companies; now they source a significant amount of their supply either directly from a producer, a producer's marketing affiliate, or from an independent marketer.

According to an American Gas Association (AGA) survey of its members on hedging and supply procurement practices in the winter season of 2005–06, most LDCs now buy the majority of their supply directly from the marketing affiliate of a gas producer or from an independent marketer. Of the 29 companies responding to a question about their source of gas supply during their peak day of consumption, just two reported buying any portion of their supply directly from a pipeline company, while seven said they purchased from the marketing affiliate of a pipeline company. In both cases, only one company reported purchasing more than 25% of its peak day supply from a pipeline company or its marketing affiliate. Only four respondents said they did not purchase any supply from an independent marketer, and just six said they had no dealings at all with a producer.

Supply contract options

LDCs purchase natural gas using a number of different kinds of contractual arrangements, the terms of which can have a significant impact on the ultimate cost of the gas paid by customers. Supply contracts can be made for different durations: long-term contracts stretching for a year or longer, mid-term contracts of more than a month but less than a year, or monthly or even daily periods. For their peak-month supplies, LDCs tend to rely primarily on mid-term contracts (one to 12 months), though more than half of the respondents to the AGA survey reported using long-term contracts for as much as 50% of their peak month supply.

In addition to differing timeframes, gas supply contracts can include one of several different pricing mechanisms, including a fixed price for the contract's duration, a weekly average price, a daily price, a first-of-the-month index, a three-day average, or the price of futures contracts traded on the New York Mercantile Exchange (NYMEX). The AGA survey showed that 20 of 22 LDC survey respondents used first-of-the-month pricing for their long-term contracts, and only a few used other pricing mechanisms. For mid-term contracts, first-of-the-month pricing was still the most common, though fixed, daily, and NYMEX-based pricing mechanisms also were used.

In addition to their physical supply contracts, LDCs often will use financial derivatives to hedge the cost of gas for their customers. These financial instruments—futures, options, and swaps—are available through an organized, regulated exchange (such as NYMEX), as well as in the "over-the-counter" market, from trading desks at various commercial banks, investment banks, marketers, and other natural gas intermediaries.

How an LDC purchases its supply, and whether it uses financial futures to hedge risk, often is heavily influenced by the type of regulatory regime under which the LDC operates. LDCs must convince regulators that their gas purchases were prudent and reasonable, or they may not be granted full reimbursement by the commission.

Recovering gas supply costs

LDCs supply natural gas to customers who have not arranged to buy gas from an independent marketer. While recovering the cost of gas appears simple enough in theory, in practice it can be quite complicated. Gas prices fluctuate from day to day and from month to month, whereas rates may be set for years into the future. This timing mismatch creates a risk that utilities may not fully recover the cost of gas purchased if what they collect for gas supplied is insufficient to cover their costs. Even more worrisome is the fact that regulators may not allow utilities to collect the full cost of gas if their initial cost estimates prove unreliable.

States have widely varying procedures in place for LDCs to recover the cost of gas supplied to customers. Some have automatic pass-through mechanisms linking customer prices to gas price indices that change prices monthly. In other states, however, LDCs must wait until the season is over and then apply to regulators to recoup undercharges. They then run the risk that regulators will not permit full recovery of their gas procurement costs in the next rate case. During times of high gas prices, even delayed recovery of gas supply costs can hurt an LDC's liquidity, forcing it to increase its borrowings (thus raising its interest expense); in extreme cases, this can hurt its credit rating.

Transportation

The physical properties of natural gas make it difficult to transport by any means except a dedicated pipeline. While a few LDCs have their own gas production that can be used to supply customers, long-distance pipelines are the only realistic way for most LDCs to secure enough supply to satisfy full customer demand.

Until the mid-1980s, LDCs purchased their gas directly from the transmission pipeline serving their area, paying a single price for the gas together with any additional charges for transportation and storage. While this arrangement worked well in assuring stability of supply, it was inefficient, as it required LDCs to contract enough gas to meet their peak demand levels throughout the year, even if the pipeline capacity went unused. These costs were passed along to gas customers.

The regulatory reforms that began in 1984 and were completed in 1992 allowed LDCs to shop around for their gas from producers, instead of being forced to buy from pipeline companies. They also were permitted to sell unused pipeline transportation capacity to others in what is known as a "capacity release market." As a result, LDCs now use a range of options to meet their transportation requirements, including gas released from storage, short-term firm transportation rights, interruptible transportation, released capacity, and "gray market" services (capacity repackaged with supply or other services by LDCs or independent marketers).

The AGA's survey found that most LDCs still used firm transportation for the majority of their peak month supply: 16 of 31 responding companies said that they buy between 50% and 75% of their peak month supplies via firm transportation. Only two of 30 companies reported purchasing peak month supplies via interruptible transportation, and then for less than 25% of their supply.

Storage

Natural gas is bulky and expensive to transport. Because transportation capacity to large demand centers cannot be increased on short notice, gas storage facilities play an important role in LDCs' efforts to secure supply. In particular, storage is most important during times of peak demand, when demand exceeds pipeline transmission capacity. About 20% of the gas used during winter months comes from storage, according to the AGA, while 50% or more of the gas burned on an extremely cold day may come from storage.

For these reasons, gas storage facilities have become extremely important to LDCs. Gas can be stored in one of several types of facilities, including salt caverns, disused mines, aquifers, hard rock caverns, or depleted gas reservoirs. LNG also can be stored in specially constructed insulated containers near regasification terminals. Small volumes of compressed gas can be stored in tanks commonly referred to as gas holders. Such storage facilities are used for shipments to or from areas where pipelines are not available.

Owning or controlling storage reservoirs allows LDCs to guarantee future deliveries and to actively manage inventories against fluctuating natural gas prices. Control or ownership also reduces the reliance on transmission pipeline capacity and limits the potential effect of a pipeline outage. Inventory can be managed by purchasing gas during times of weak demand, when prices are low, and storing it for use during periods of peak consumption. Storage capacity also can be leased to third parties, providing an additional source of revenue.

Because US natural gas consumption peaks in the winter, producers store gas during the months when temperatures and demand are moderate (April through October) and withdraw gas during the heating season (November through March). The US government, commodity traders, and LDCs track storage levels extremely closely to determine demand levels, supply availability, and likely future price trends.

Storage facilities may be classified as either seasonal supply reservoirs or high-deliverability sites. Seasonal supply sites are designed to be filled during the 214-day non–heating season and to be drawn down slowly during the 151-day heating season. In comparison, high-deliverability sites are situated to provide a rapid drawdown or rebuilding of inventory to respond to such needs as volatile peaking demands, emergency backup, and/or system load balancing. High-deliverability sites can be drawn down in 20 days or less and refilled in 40 days or less.

Gas storage capacity is an important tool for LDCs to manage price volatility. A report by the FERC in October 2004 said that improving storage infrastructure was the best way to manage volatile prices. The FERC concluded that existing storage capacity was adequate, but that the industry would benefit from additional capacity because it would help smooth price spikes by increasing the amount of supply close to demand centers. The further a demand center is removed from supply sources, the more that storage will help, the FERC report concluded.

END MARKETS

Residential, commercial, and industrial customers, as well as electric power plants, use natural gas for a variety of purposes, including heat, power generation, and as the raw material for products such as chemicals and fertilizer. Each group displays markedly different responses to changing weather patterns, price levels, and economic activity. Before the gas even reaches these customers, however, some is used for other purposes: 5.5% is used for lease and plant fuel in processing the gas and 2.8% is used for transportation. Thus, of the 22.8 Tcf of gas consumed in the US during 2009, 91.7% (or 20.9 Tcf) reached the end markets.

LDCs classify their customers as either firm or interruptible. Industrial customers, as well as some commercial customers, have the option of choosing firm gas supply, regardless of their level of demand, for a correspondingly higher price. For customers that can accommodate temporary interruptions or switch to alternative fuels, interruptible service and its corresponding price advantage may be preferable. Residential customers always receive firm service.

Electricity generation

In 2009, electric power generators were the largest class of natural gas customer, with relatively few customers accounting for about 32.9% of US gas delivered to consumers. Gas-fired power generation capacity has grown rapidly in the United States in recent years, for several reasons. Shorter construction times and lower capital investment requirements than other types of power plants made gas-fired power plants an attractive investment during a time of rising electricity prices. New combined cycle technology has increased the efficiency of gas-fired generation, and concern over the environmental impact of coal-fired and nuclear generation has encouraged more gas-fired plants.

Power generators are even more sensitive to changing natural gas prices than industrial users, operating only when electricity prices are high enough to make burning gas for power profitable. Gas consumption by power generators fell by almost 10% in 2003, when rising gas prices made it less profitable to burn as a fuel for generating power. However, generator consumption of natural gas rose in 2004 by 6.4%, in 2005 by 7.4%, in 2006 by 6.0% and in 2007 by 10%—even though prices were still high—due both to increasing power prices and new generation fueled by gas. However, in 2008, consumption fell by 2.5%, reflecting a cooler summer than in 2007. In 2008, the EIA data said that gas-fueled power plant additions provided an additional 7.7 gigawatts (GW) of net power capacity. However, for the second time ever, new non-hydro renewable capacity increased more than any other type, adding 8.2 GW of capacity in 2008, with a vast majority of that new capacity coming from wind turbines.

Several factors other than price can affect short-term natural gas demand patterns for electric power generators. Weather-related events—as well as other developments, such as plant outages, that can raise or lower electricity prices—can cause sudden spikes in gas demand. The rising share of gas demand from electric power producers has created a new "summer peak" in demand, as gas-fired power generators increase their use during periods of hot weather to meet higher power demand for air conditioning.

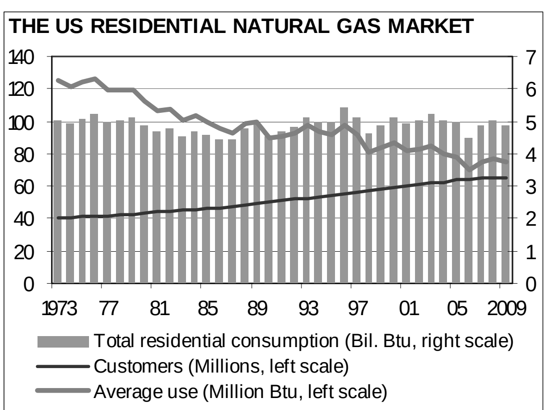
The industrial market

Industrial consumers were a very close second largest source of demand for natural gas in 2009, accounting for about 29.3% of the total consumer volumes. In 2008 (latest available data), about 196,500 different industrial customers used natural gas as fuel to produce heat and steam, or as feedstock for chemicals and fertilizer. Chemical makers are the largest group of industrial gas users, with feedstock use of gas accounting for about 8.2% of total US industrial demand. Makers of paper, steel, and building materials are also large gas consumers.

Consumption by industrial users tends to be more sensitive than commercial or residential demand to changes in economic activity and price, because industrial customers have greater ability—and incentive—to alter their consumption as market forces dictate. Because demand per customer is much larger than it is for commercial or residential users, one industrial customer's decision will have a larger impact on total demand.

The residential market

Residential gas users, numbering about 65.2 million in 2008, accounted for about 22.7% of gas volumes delivered to customers. While residential customers are more expensive to supply as a result of the billing and customer service infrastructure required, they pay substantially higher prices than industrial or commercial customers and thus supply the lion's share of utility profits. Based on 2009 data from the EIA, the yearly average for residential natural gas prices was about $11.97 per thousand cubic feet (Mcf)—22.8% higher than commercial prices ($9.75/Mcf), 127% above average industrial prices ($5.27/Mcf), and 145% above prices paid by electric power generators ($4.89/Mcf).



Btu-British thermal units.
Source: US Energy Information Administration.

Approximately two-thirds of residential natural gas demand is for space heating, though that demand is confined mainly to winter months. Gas also is used to power home appliances such as water heaters, stoves, clothes dryers, and fireplaces. Although overall levels of natural gas demand by residential customers rise and fall with the severity of winter weather—and also with other factors, such as population growth and housing trends—

the use of natural gas per residential customer is in a long-term decline. Since 1978, natural gas demand per residential customer has exhibited a 1.5% annual compound average shrink rate, according to calculations using data from the EIA. However, since 1998, per customer residential demand has slowed its rate for shrinkage to just 0.6%, possibly reflecting slowing market penetration rates for energy efficient appliances. Demand is likely to continue to drop by about 0.5% each year through 2020, assuming normal weather patterns, due mainly to continuing market penetration of efficient gas furnaces and appliances.

The commercial market

Commercial customers comprise nonmanufacturing businesses such as hotels, restaurants, wholesalers, retailers, and other service-oriented businesses. Natural gas used by state and federal agencies for nonmanufacturing purposes is also counted as commercial demand. The commercial market, with about 5.3 million customers in 2008 (latest available data), is smaller than the industrial, residential, or power generation markets; it accounted for 14.9% of total consumer demand in 2009.

Gas demand is somewhat less seasonal for commercial customers than for residential customers. Slightly more than half of all commercially consumed gas is currently used for purposes of space heating, with the remainder used for water heating, cooking, and a variety of other purposes. The commercial customers' compound annual growth rate was 1.0% between 1983 and 2008; during the same period, however, per-customer usage fell 0.2% annually. More efficient space- and water-heating appliances accounted for most of the decline; gas customers switching to electricity for cooling purposes also contributed.

Other uses

Small amounts of natural gas (0.15% in 2009) are used as vehicle fuel and as a component of fuel cell technology. Many decades from now, these markets could become significant consumers of natural gas. The number of natural gas vehicles in use in the United States has been rising, helped by technological advances in natural gas–fired engines. Since 1999, the compound annual growth rate for other gas usage has been 10.6%. Natural gas vehicles may provide a bridge to the fuel cell vehicle of the future, which has the potential to create enormous demand for natural gas. Natural gas contains high concentrations of hydrogen and already is supported by a vast distribution system.

KEY INDUSTRY RATIOS AND STATISTICS

◆ **Heating and cooling degree days.** Natural gas is consumed in proportion to extremes in temperature. Residential, commercial, and industrial markets typically use gas for heating enclosed spaces (space heating). In the United States, the heating season generally is considered to last from November through March, though it's somewhat longer in the northern part of the country and somewhat shorter in the South.

Cooling degree days occur during the warm summer months when customers run air conditioning units. This measure also is gaining importance as a barometer of natural gas consumption because electric utilities are increasingly operating gas-fired power plants.

Space heating accounts for approximately two-thirds of residential gas demand and half of commercial use. Consequently, shifts in the relative severity of weather during the heating season affect year-to-year changes in natural gas consumption in these sectors.

When analysts make projections of future gas demand, they assume "normal" weather, quantified in terms of heating and/or cooling degree days. A degree day is a measure of the relative warmth or coldness of the air, based on how far the daily mean temperature falls above or below a reference temperature, usually 65 degrees Fahrenheit. For example, a day with a mean outdoor temperature of 35 degrees Fahrenheit would be counted as a 30-degree heating day. The National Oceanic and Atmospheric Administration (NOAA), an agency of the US Department of Commerce, calculates reference temperatures on a monthly basis. Given the variability of the weather, natural gas demand always will be subject to some unpredictable volatility.

◆ **Real gross domestic product (GDP).** Although weather is the main cause of swings in gas consumption, weather-normalized gas demand historically has tended to follow the overall economy. Average annual growth in US natural gas demand has typically run at a pace of slightly less than three-quarters of real GDP growth. Real GDP is the market value of the nation's output of goods and services, adjusted for inflation; it is reported quarterly by the Department of Commerce.

The economy affects all three sectors of the gas market. In the residential sector, the number of housing starts is influenced by economic conditions. For commercial and industrial customers, an increase in business activity translates into greater energy consumption, despite increasingly energy-efficient equipment. For an individual utility or energy merchant, demand growth depends heavily on economic trends within its geographic region. These can vary somewhat from GDP trends.

◆ **Housing starts.** The residential market offers the widest margins and the lion's share of profits for natural gas distributors. For this reason, housing starts—the number of residences on which construction has begun in a given period—are significant for the natural gas industry. These figures, reported as seasonally adjusted annualized rates (SAAR), are available from the Department of Commerce on a monthly basis.

The residential market accounted for almost two-thirds of natural gas utility profits. It is characterized by a larger number of customers who individually consume much less fuel than is the case in industrial and commercial markets. Accordingly, residential customers pay more on a per-unit basis than industrial and commercial customers do.

The most important factors contributing to changes in demand in the residential market are new housing, conversions from alternate fuel heating to natural gas, and weather. Growth in space heating installations is not the only benefit of a robust housing market. The gas industry also benefits from the increase in appliance shipments. However, appliance design improvements have reduced per-unit natural gas consumption over time.

◆ **Interest rates.** The regulated and capital-intensive nature of the utility industry makes a utility's financial performance very sensitive to the level of interest rates and available returns. Utility rates are determined by state regulatory agencies based on operating costs, capital investments, and the cost of capital. Changes in overall interest rates affect utility rates via the allowed cost of debt and the allowed return on equity (ROE). When interest rates drop substantially, the rates that utilities are allowed to charge are likely to be lowered as financing cost savings are passed on to customers.

Income-oriented investors are sensitive to interest rates when they evaluate a utility company's shares. If interest rates are rising, investors can receive comparable returns elsewhere. To invest in a utility, income-oriented investors look for a large dividend yield or consistently growing dividend distributions to compensate for the risk of owning stock versus a fixed-income security. The dividend tax cut of 2003 makes dividends more attractive relative to fixed-income securities and other investment alternatives.

HOW TO ANALYZE A NATURAL GAS COMPANY

The performance of natural gas companies depends heavily on the mix of their operations. The owners of local distribution companies (LDCs) typically have other operations—both regulated (long-distance pipelines and electricity distribution) and unregulated ("merchant energy" power generation assets and wholesale gas marketing desks). Each of these businesses has a unique competitive position, financial condition, and exposure to changing market prices and regulatory regimes.

The earnings streams from unregulated generation and trading businesses are much more volatile, as they can be subject to wild swings in commodity prices. Pipelines are more similar to LDCs, but they are more loosely regulated and subject to more competition. Analytical considerations for LDCs, merchant energy assets, and pipelines are described separately following.

LOCAL DISTRIBUTION COMPANIES

In analyzing an individual LDC, it is important to consider a number of issues related to energy markets and company management.

Competitive position

To assess where an LDC stands competitively, first compare the rates it charges its customers with those of neighboring utilities and the national average. Favorable comparisons are generally indicative of a company's focus on cost controls. Traditional utility regulation (versus "performance-based ratemaking") does not allow an LDC to profit from cost-savings initiatives associated with pass-through ratepayer expenses. However, low rates can engender healthy relationships with regulators and help fend off competitive threats.

Regulatory reforms have made it vital to track competitive threats. Independent gas marketers have proliferated, making inroads into the utilities' service areas by competing for large gas customers. Increasingly, interstate pipeline companies are trying to bypass the LDCs by distributing gas directly to large-volume industrial users.

Note how an LDC faces these challenges. Has it secured at-risk customers through long-term contracts or flexible pricing agreements? Does it offer bundled services? Has it formed its own marketing arm to compete directly with gas marketers? Has it obtained performance-based regulation (PBR) mechanisms that permit efficiencies to be shared between shareholders and ratepayers?

Location and customer mix

Demand growth occurs in several ways: an increase in customers in a company's service area, increased consumption by existing customers, or both. An expanding economy and above-average population growth within an LDC's service territory are generally favorable characteristics.

Customer growth does not necessarily translate into greater total volumes delivered, however, because the rate of gas consumption per household has been declining for years due to energy-efficient appliances. If state regulatory commissions do not compensate LDCs appropriately for declining consumption patterns, it could slow the capital investment a company needs to make to provide gas utility connections to a growing population.

It is important to note the proportion of an LDC's residential customers to total customers in a service territory. A greater percentage of residential customers will yield a more stable and predictable revenue stream. Industrial customers and electric utilities that use gas tend to be more price-sensitive. It is also preferable for an LDC to limit the percentage of its business that comes from any single large customer. If one customer accounts for a significant portion of a utility's sales, the analysis must focus on that customer's stability and the utility's competitive position in retaining its business.

While a greater proportion of residential customers generally confers stability, excessive residential exposure has its drawbacks. Residential customers are "full-service" customers, meaning that the LDC must always fulfill all customer demand, however great or small. This creates both inventory management and commodity price risks for the LDC. If too much gas is left over after the heating season, the LDC must store or sell excess supplies, which can reduce earnings.

A further complication is that residential demand tends to be greatest when gas prices are high (during a very cold winter, for example). State public utility commissions often subject the commodity pass-through expenses incurred by LDCs to "prudency" reviews. If an LDC's gas procurement strategy is found to be insufficiently judicious, the company can be required to absorb some commodity costs. In addition, residential bad-debt expense tends to increase when higher commodity prices and increased consumption drive up monthly bills. Analysts can gauge an LDC's susceptibility to inventory management and commodity price risks by evaluating its gas procurement and price hedging strategy, its relationship with regulators, and its management of bad debt.

The penetration rate for residential gas heating in a utility's service territory is important. For example, in many older communities in the Northeast, the conversion of customers from oil to gas heating has boosted revenue growth.

Regulatory environment

LDCs are subject to rate of return regulations controlled by state utility commissions. Thus, it is important to study trends at the regulatory commission(s) with jurisdiction over an LDC's service territories. Compare authorized rates of return with the rates allowed industry peers. Are there automatic "true-up" mechanisms that allow pension, bad debt, and other costs to be passed through automatically to ratepayers? When will the next rate filing take place? Has performance-based regulation been approved, or could it be approved by the state utility commission?

Timing requests for rate reviews are important. Even if an LDC seeks higher rates based on reasonable capital expenditures, if interest rates are low (affecting the allowed return on equity) and commodity costs are high (affecting ratepayer pocketbooks), regulators may be unwilling to grant relief.

For diversified utility companies, regulatory issues affecting other utility operations, such as electric or water, must be considered. The impact that the 2000–01 power crisis had on California's diversified utilities exemplifies this.

Gas supply and demand

To determine its need for gas supply and transportation capacity, an LDC must decide how much gas to contract on a firm basis. Conversely, how much should it buy on the spot market, and how much capacity should be interruptible? How much storage capacity does it need to meet demand on peak days?

A well-run LDC is likely to obtain gas from various producers or marketers, from different gas basins in the United States and Canada, and/or from different pipeline routes. It generally will have firm purchase contracts—preferably for an intermediate term—with minimal take-or-pay provisions (which require it to purchase specified quantities of natural gas whether needed or not). A distribution company must carefully manage its storage requirements, as well as its gas supply and transportation arrangements. If it is not successful in these regards, an LDC faces a greater risk of hindsight prudence reviews by regulators and potential disallowance of its purchased gas and transportation costs.

Storage

An LDC's access to storage capacity helps it control both the supply and cost of its gas. Storage helps it to meet increased demand on peak days and allows it to purchase gas during off-season months, when prices are lower.

An LDC that owns storage facilities can lease any unneeded capacity to others. Conversely, an LDC that does not own storage facilities must continually ask how much gas it needs and how much it should pay for the gas. The problems associated with not owning storage facilities can lead to unstable costs. The creation of storage operations represents a major capital commitment. Thus, it is not surprising that larger gas utilities, with more customers and volume demand, tend to take greater advantage of the storage option.

Unregulated activities

To remain viable in a market-driven environment, an LDC's management team must develop strategies to address competitive pressures. These strategies could involve the introduction of wholesale trading and marketing operations, investment in competitive retail distribution, or the development of natural gas exploration and production operations.

Every foray into unregulated activities carries greater potential for risks and rewards than do regulated utility operations. The risks are even higher, however, when utility managers move into business lines in which they have little experience. Investments in unregulated operations may put undue strains on a utility's credit and could dissuade state regulators from approving mergers, new performance-based regulations, or other utility initiatives.

Looking at the income statement

Due to the vagaries of weather and the constraints of regulation, two common profitability measures—net income and earnings per share (EPS)—are not as important in analyzing a utility as in analyzing some other companies. For a better gauge of value and performance, analysts look at how a company manages its financial resources and at its overall health. The three most important items to examine in analyzing a gas distribution company's income statement are net revenues, operating expenses, and interest expense.

◆ **Net revenues.** For utilities, growth in net revenue (revenues, less fuel expense) is somewhat predictable because of the regulatory constraints on rates. Nonetheless, past sales trends should be evaluated. Did growth come from a rate increase? An improving economy? Rising weather-related demand? Expectations for the future also should be considered.

◆ **Operating expenses.** As competition among gas utilities grows, cost-containment and productivity efforts are crucial to earnings performance. Because fuel costs fluctuate widely, the analyst should pay close attention to nonfuel operating and maintenance costs. Changes in expenses from one period to the next should be noted, along with whether expenses are trending up or down as a percentage of net revenues. The number of customers served per employee is an effective means of tracking trends in operating efficiency.

◆ **Interest expense.** The utility industry is extremely capital-intensive, so interest payments are a utility's most significant nonoperating expense. Analysts calculate the pretax interest coverage ratio, which indicates how much of the company's pretax income is needed to meet interest payments. This measure becomes increasingly important as a company engages in greater levels of unregulated operations, due to the uncertainty of earnings derived from such activities.

Evaluating the balance sheet

When looking at an LDC's balance sheet, pay close attention to the company's capitalization ratio: long-term debt as a percentage of total capital.

Because public utilities require a substantial investment in long-term assets, they traditionally have had significantly more long-term debt on their balance sheets than companies in other industries. Investors usually have accepted these higher debt levels because of the regulated nature of the industry (which ensures income that largely covers the cost of the debt) and utilities' relatively stable earnings (which consistently provided sufficient funds to cover interest payments). Greater exposure to unregulated activities, however, increases the risk associated with heavy indebtedness.

It is important to compare an LDC's capitalization ratio with its own historic levels, as well as with those of its peers. These findings then should be put in the context of changes in the LDC's mix of regulated and unregulated operations.

Assessing cash flow

A review of cash flow trends often can give clues to a utility's health. The company should generate sufficient cash to meet all ongoing expenses. It also needs cash to fund business expansion and, in most cases, to pay dividends.

A firm's ability to tap capital markets on an ongoing basis must be considered. Therefore, it is important to look at the company's cash flow relative to its debt. A positive and growing cash flow lets the utility finance more of its expansion internally and reduces its dependence on the capital markets.

PERFORMANCE AND VALUATION MEASURES

These measures include return on equity, return on assets, the ratio of earnings to fixed charges, the price-to-book ratio, the price/earnings ratio, and dividend payments.

◆ **Return on equity (ROE).** This performance measure reveals how well a company invests its capital. It is calculated by dividing net income (less preferred dividend requirements) by average shareholders' equity.

◆ **Return on assets (ROA).** This performance measure shows how efficiently a company uses its assets. It is calculated by dividing utility operating income by total plant assets less accumulated depreciation.

◆ **The ratio of earnings to fixed charges.** This calculation reveals a company's ability to cover fixed charges (amortization and interest expense) with pretax earnings.

◆ **Price-to-book (P/B) ratio.** Comparing the market price of the company's shares with its book value indicates how much investors are willing to pay for the company's assets. LDCs usually do not have high levels of goodwill. In selected cases, though, growth-oriented LDCs that have made significant acquisitions may appear to have disproportionately higher book values (and lower P/B multiples) than their peers, due to their goodwill balances.

◆ **Price/earnings (P/E) ratio.** Another way to evaluate the current market price of the utility's shares is to look at the P/E ratio. Compare company's current P/E (based on both trailing and future estimated earnings) with that of its industry peers and with its own historical range. Given their lower EPS growth rates, utility stocks normally trade at a discount to the overall market P/E. When making comparisons of companies within the utility sector, investors tend to pay a higher P/E for, and accept a lower dividend yield from, shares of a utility company with above-average earnings growth potential.

A useful related measure is the P/E to growth (PEG) ratio: the stock's P/E, divided by the present (or future) earnings growth rate. Is the PEG ratio higher than, lower than, or equal to the industry overall? How does it compare with the company's historical PEG ratios?

◆ **Dividend payments.** In general, most utility shareholders do not view a utility stock as a high-growth investment; rather, they are most interested in the stock's total return potential—its share appreciation combined with its dividend yield. Dividend yield is a larger component of total expected return on a utility stock than for the typical industrial company stock. Consequently, a utility's ability to pay a dividend—and to provide steady dividend increases—is of paramount importance. To determine if a dividend is secure, the analyst should check the payout ratio (the annual dividend divided by earnings per share). A utility that is paying out too high a percentage of its earnings may need to cut future payments if earnings weaken.

When looking at an individual company, it is important to determine the utility's dividend policy. As many utilities began investing in unregulated activities, they sought to reduce their payout ratios by either immediately cutting the dividend or holding it constant as earnings rose over time. In cases where the dividend payout ratio is falling, investors must analyze the potential returns from growth-oriented unregulated investments versus the value of the forgone dividend stream.

MERCHANT ENERGY OPERATIONS

Unregulated power generation, wholesale gas marketing, and other merchant energy operations need a stronger balance sheet than LDC businesses. Energy marketing and trading activities demand high levels of financial security in order to assure both trading counterparties and credit rating agencies that a company can survive volatile swings in the energy markets. In contrast to regulated utilities, the value of unregulated assets owned by energy merchants can fluctuate wildly, exposing otherwise healthy balance sheets to asset write-downs during bad times. To safeguard against such volatility, many companies have attempted to lock in favorable prices with long-term customer contracts.

An analyst must evaluate the proportion of merchant energy business that is exposed to short-term market risk and the ability of the company's liquidity and balance sheet to persevere through industry downturns. Furthermore, one also must evaluate the credit profile of a company's major contractual counterparties. Hedging unregulated assets through long-term contracts with weak counterparties may provide very limited protection against a cyclical downturn.

The volatility of merchant energy operations has cast a light on company growth initiatives as well. Business plans that require years of capital spending far in excess of operating cash flows can become a liability during an industry downturn, when financial liquidity takes on increased importance. An analyst must evaluate the quality of a company's new merchant energy investments and the flexibility of capital spending commitments.

It is important to evaluate the energy merchant's risk management control. This concept covers asset management, trading limits and monitoring, and debt management. Only recently have merchant energy managers begun to develop consistent industrywide reporting practices. Disclosure and transparency have increased with the backlash against the sector in recent periods. An analyst must make use of these disclosures (including value-at-risk measures, proportion of hedges, credit exposure, debt maturity schedules, and the like) to evaluate the true risk/reward opportunities presented by each unregulated merchant energy business.

PIPELINES

Interstate pipelines have both utility and merchant energy characteristics. They are similar to monopoly utilities in that they require significant capital expenditures, involve a permitting process, and are subject to price controls. However, an interstate pipeline's service territory can be expanded through new permitting and construction, whereas this is not usually the case for LDCs. Pipelines are also subject to competition from other pipelines that are built close enough to contend for institutional customers.

Pipelines differ from LDCs in that their business generally relies on a limited number of large institutional customers (including wholesale marketers, exploration and production companies, LDCs, and large industrial companies). Such high customer concentration increases the risks associated with bad debt expense. When evaluating a pipeline company, an analyst must investigate demand and supply growth along a pipeline's footprint, opportunities for pipeline expansion, applications for competitive pipeline developments, and the growth prospects and credit quality of shippers along the pipeline's system.

Pipeline capacity utilization is affected by the location of natural gas supply sources and shifts in consumption patterns. A change in source requires new pipelines to transmit gas from growing production centers (such as the Rockies). The increasing use of LNG imported via tanker also will affect the need for and utilization of pipeline assets.

The demand side of the equation is subject to potential secular shifts. For example, growth in the number of gas-fired electric generating plants has had a major impact on geographical demand patterns. The analyst must be aware of longer-term supply and demand trends that could increase or decrease the value of pipeline assets.

Many pipeline companies historically have engaged in various unregulated merchant energy activities through subsidiary operations. Thus, the analyst must be careful not to assume that a company has a low-risk profile just because it owns substantial regulated pipeline assets.

A number of pure-play pipeline businesses are owned by master limited partnerships (MLPs). MLPs trade on exchanges just like common stocks, but the businesses avoid income taxation by paying out nearly all free cash flows to shareholders. These income-oriented investments generally trade based on their yield, distribution growth potential, and volatility of cash flows.

Because MLPs cannot use operating cash flows for growth-oriented capital expenditures, they depend on the ability to continuously raise fresh debt and equity capital to fund new investment. Unlike other pipeline companies, MLPs generally cannot be held by pension funds due to current tax obligations generated from their partnership structure. Accordingly, shares of publicly traded MLPs generally are held by smaller retail investors.

The general partners (GPs) for MLPs often have performance participation awards that provide the GPs with larger and larger interests in MLP distributions as the dividend is raised. An analyst needs to evaluate an MLP's capacity to raise distributions in light of growth opportunities, access to capital markets, and GP performance participation awards. ■

INDUSTRY REFERENCES

PERIODICALS

Inside FERC
Platts Retail Energy
Gas Daily
http://www.platts.com
The first two are weekly newsletters providing an authoritative source of information on the workings of the Federal Energy Regulatory Commission (FERC) and its impact on the regulated industry, and industry news, respectively. The third is a daily that provides detailed coverage of natural gas prices. (Platts, like Standard & Poor's, is part of The McGraw-Hill Cos. Inc.)

Natural Gas Week
http://www.energyintel.com
Weekly newsletter; covers industry news.

Platts Gas Daily
http://www.platts.com/products.shtml
Daily newsletter; covers gas industry news.

Public Utilities Fortnightly
http://www.pur.com
Biweekly magazine; covers the electric and gas utility industries.

The Waterborne LNG Report
http://www.waterborneIng.com
Weekly report; gives data and estimates of liquefied natural gas (LNG) import and export volumes to the US and Europe.

TRADE ASSOCIATIONS

American Gas Association (AGA)
http://www.aga.org
Natural gas industry association that conducts technical research, compiles authoritative statistics, and helps create standards for industry equipment and products.

American Public Gas Association (APGA)
http://www.apga.org
Represents municipal gas systems.

Center for Liquefied Natural Gas
http://www.lngfacts.org
Represents LNG asset owners and operators, gas transporters, and natural gas end users.

Gas Technology Institute (GTI)
http://www.gastechnology.org
Not-for-profit technology organization that conducts research, development, and commercialization programs for the natural gas industry.

Industrial Energy Consumers of America
http://www.ieca-us.com
Represents energy-intensive manufacturing industries.

Interstate Natural Gas Association of America (INGAA)
http://www.ingaa.org
Advocates regulatory and legislative positions for the North American natural gas pipeline industry.

National Association of Regulatory Utility Commissioners (NARUC)
http://www.naruc.org
Represents individual states' viewpoints on regulation.

The Natural Gas Supply Association
http://www.ngsa.org
Represents US natural gas producers.

CONSULTANTS

Baker Hughes Inc.
http://www.bakerhughes.com
Firm providing various oil and gas industry consulting services to its clients. It is also considered to be the authority on rig count data and publishes weekly and monthly rig count information.

Global Insight Inc.
http://www.globalinsight.com
Research firm providing economic data, forecasts, analysis, and consulting. Among its many publications is the *Monthly Natural Gas Price Outlook*.

Platts/The McGraw-Hill Cos. Inc.
http://www.platts.com
Strategic energy information, consulting, and publishing firm.

SNL Financial
http://www.SNL.com
Research firm providing regulatory, financial, market, and M&A data on several industries, including energy.

GOVERNMENTAL AND REGULATORY BODIES

Energy Information Administration (EIA)
http://www.eia.doe.gov
Agency within the US Department of Energy; supplies publications and statistics on the natural gas industry, as well as on power, coal, and a variety of other energy areas, including supply, consumption, and transportation issues.

Federal Energy Regulatory Commission (FERC)
http://www.ferc.gov
Agency within the US Department of Energy that exercises regulatory control over the electric power and natural gas industries. It also regulates producer sales of natural gas in interstate commerce and, for each of several categories of natural gas, establishes uniform ceiling prices that apply to all sales nationwide.

Federal Trade Commission (FTC)
http://www.ftc.gov
Independent agency reporting to the US Congress, the FTC is charged with maintaining competition and safeguarding consumers' interests. Reviews proposed mergers involving electric and gas utility companies; may analyze regulatory or legislative proposals affecting energy market competition or the efficiency of resource allocation.

US Department of Energy (DOE)
http://www.energy.gov
Federal science and technology agency whose research supports the nation's energy security, national security, and environmental quality. Introduced to the US Cabinet in 1977, the DOE includes the Office of the Secretary of Energy, the FERC, and other agencies.

National Energy Board (NEB)
http:// www.neb-one.gc.ca
Independent federal agency established in 1959 by the Parliament of Canada to regulate international and interprovincial aspects of the oil, gas and electric utility industries in Canada.

COMPARATIVE COMPANY ANALYSIS — NATURAL GAS DISTRIBUTION

Operating Revenues

			Million $							CAGR (%)			Index Basis (1999 = 100)				
Ticker	Company	Yr. End	2009	2008	2007	2006	2005	2004	1999	10-Yr.	5-Yr.	1-Yr.	2009	2008	2007	2006	2005
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	2,317.0 F	2,800.0 F	2,494.0 F	2,621.0 F	2,718.0 F	1,832.0 A,F	1,068.6	8.0	4.8	(17.3)	217	262	233	245	254
ATO	† ATMOS ENERGY CORP	SEP	4,969.1 F	7,221.3 F	5,898.4 F	6,152.4 F	4,973.3 A,F	2,920.0 F	690.2 F	21.8	11.2	(31.2)	720	1,046	855	891	721
EGN	† ENERGEN CORP	DEC	1,435.5 A,F	1,568.9 F	1,435.1 D,F	1,338.5 D,F	1,128.4 D,F	937.4 D,F	497.5 A,F	11.2	8.9	(8.5)	289	315	288	269	227
EQT	[] EQT CORP	DEC	1,269.8 F	1,576.5 F	1,361.4 F	1,267.9 D,F	1,253.7 D,F	1,191.6 F	1,062.7 A,F	1.8	1.3	(19.5)	119	148	128	119	118
LG	§ LACLEDE GROUP INC	SEP	1,895.2 F	2,209.0 D,F	2,021.6 F	1,997.6 A,F	1,597.0 F	1,250.3 F	491.6 F	14.4	8.7	(14.2)	386	449	411	406	325
NFG	† NATIONAL FUEL GAS CO	SEP	2,057.9 A,F	2,400.4 F	2,039.6 D,F	2,311.7 F	1,923.5 D,F	2,031.4 F	1,263.3 F	5.0	0.3	(14.3)	163	190	161	183	152
NJR	§ NEW JERSEY RESOURCES CORP	SEP	2,592.5 F	3,816.2 F	3,021.8 F	3,299.6 F	3,138.2 F	2,533.6 F	904.3 F	11.1	0.5	(32.1)	287	422	334	365	347
GAS	[] NICOR INC	DEC	2,652.1 F	3,776.6 F	3,176.3 F	2,960.0 F	3,357.8 F	2,739.7 F	1,615.2 F	5.1	(0.6)	(29.8)	164	234	197	183	208
NWN	§ NORTHWEST NATURAL GAS CO	DEC	1,012.7 F	1,037.9 F	1,033.2 F	1,013.2 F	910.5 F	707.6 F	455.8 D,F	8.3	7.4	(2.4)	222	228	227	222	200
OKE	[] ONEOK INC	DEC	11,111.7 F	16,157.4 F	13,477.4 F	11,896.1 D,F	12,676.2 D,F	5,988.1 F	1,842.8 F	19.7	13.2	(31.2)	603	877	731	646	688
PNY	§ PIEDMONT NATURAL GAS CO	OCT	1,638.1	2,089.1	1,711.3	1,924.6	1,761.1	1,529.7	686.5	9.1	1.4	(21.6)	239	304	249	280	257
STR	[] QUESTAR CORP	DEC	3,038.0	3,465.1	2,726.6	2,835.6	2,724.9	1,901.4	924.2	12.6	9.8	(12.3)	329	375	295	307	295
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	845.4 D,F	962.0 D,F	956.4 D,F	931.4 D,F	921.0 D,F	819.1 D,F	392.5 D,F	8.0	0.6	(12.1)	215	245	244	237	235
SWX	§ SOUTHWEST GAS CORP	DEC	1,893.8 F	2,144.7 F	2,152.1 F	2,024.8 F	1,714.3 F	1,477.1 F	936.9 F	7.3	5.1	(11.7)	202	229	230	216	183
UGI	† UGI CORP	SEP	5,737.8 F	6,648.2 F	5,476.9 F	5,221.0 A,F	4,888.7 F	3,784.7 F	1,383.6 F	15.3	8.7	(13.7)	415	481	396	377	353
WGL	† WGL HOLDINGS INC	SEP	2,706.9 F	2,628.2 F	2,646.0 F	2,637.9 D,F	1,379.4	1,267.9	972.1	10.8	16.4	3.0	278	270	272	271	142
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	3,432.8 F	3,681.7 F	3,437.6 D,F	3,359.4 D,F	3,279.6 D,F	2,958.7 D,F	2,198.0 F	4.6	3.0	(6.8)	156	168	156	153	149
AEE	[] AMEREN CORP	DEC	7,090.0	7,839.0	7,546.0	6,880.0 A	6,780.0 C,F	5,160.0 A,F	3,523.6 F	7.2	6.6	(9.6)	201	222	214	195	192
AVA	§ AVISTA CORP	DEC	1,512.6 F	1,676.8 A,F	1,417.8 F	1,506.3 F	1,359.6 F	1,151.6 C,F	7,905.0 F	(15.2)	5.6	(9.8)	19	21	18	19	17
BKH	† BLACK HILLS CORP	DEC	1,269.6 D,F	1,005.8 A,C	695.9 D,F	656.9 A,C	1,391.6 A,C	1,121.7 D,F	791.9 F	4.8	2.5	26.2	160	127	88	83	176
CNP	[] CENTERPOINT ENERGY INC	DEC	8,281.0 F	11,322.0 F	9,623.0 F	9,319.0 F	9,722.0 D,F	8,510.4 D,F	15,302.8 F	(6.0)	(0.5)	(26.9)	54	74	63	61	64
CHG	§ CH ENERGY GROUP INC	DEC	931.6 D,F	1,332.9 F	1,196.8 F	993.4 F	972.5 F	791.5 F	521.9	6.0	3.3	(30.1)	178	255	229	190	186
CMS	[] CMS ENERGY CORP	DEC	6,205.0 D,F	6,821.0 F	6,464.0 D,F	6,810.0 D,F	6,288.0 D,F	5,472.0 C,D	6,103.0 A,F	0.2	2.5	(9.0)	102	112	106	112	103
ED	[] CONSOLIDATED EDISON INC	DEC	13,032.0 F	13,583.0 F	13,120.0 D,F	12,137.0 D,F	11,690.0 D,F	9,882.0 D,F	7,491.3 A,F	5.7	5.7	(4.1)	174	181	175	162	156
D	[] DOMINION RESOURCES INC	DEC	15,131.0 F	16,290.0 D,F	15,674.0 D,F	16,482.0 D,F	18,041.0 D,F	13,972.0 D,F	5,520.0 F	10.6	1.6	(7.1)	274	295	284	299	327
DTE	[] DTE ENERGY CO	DEC	8,014.0 F	9,329.0 D,F	8,506.0 D,F	9,022.0 C,D	9,022.0 D,F	7,114.0 D,F	4,728.0 F	5.4	2.4	(14.1)	170	197	180	191	191
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	7,499.8 F	14,047.8 D,F	10,292.4 A,C	6,890.7 D,F	6,962.7 C,F	4,890.6 D,F	1,098.5 F	21.2	8.9	(46.6)	683	1,279	937	627	634
MDU	† MDU RESOURCES GROUP INC	DEC	4,176.5 F	5,003.3 F	4,247.9 D,F	4,070.7 D,F	3,455.4 F	2,719.3 F	1,279.8 F	12.6	9.0	(16.5)	326	391	332	318	270
NI	[] NISOURCE INC	DEC	6,649.4 D,F	8,874.2 D,F	7,973.3 D,F	7,490.0 D,F	7,899.1 D,F	6,666.2 D,F	3,144.6 A,F	7.8	(0.1)	(25.1)	211	282	254	238	251
NWE	§ NORTHWESTERN CORP	DEC	1,141.9 F	1,260.8 F	1,200.1 A,F	1,132.7 D,F	1,165.8 D,F	1,039.0 D,F	3,004.3 F	(9.2)	1.9	(9.4)	38	42	40	38	39
NST	† NSTAR	DEC	3,050.0 D,F	3,345.4 F	3,261.8 F	3,577.7 F	3,243.1 F	2,954.3 F	1,851.4 A,F	5.1	0.6	(8.8)	165	181	176	193	175
OGE	† OGE ENERGY CORP	DEC	2,869.7 F	4,070.7 F	3,797.6 F	4,005.6 D,F	5,948.2 D,F	4,926.6 D,F	2,172.4 A,F	2.8	(10.2)	(29.5)	132	187	175	184	274
PCG	[] PG&E CORP	DEC	13,399.0	14,628.0 D	13,237.0	12,539.0	11,703.0 D	11,080.0 D	20,820.0 D,F	(4.3)	3.9	(8.4)	64	70	64	60	56
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	12,406.0 F	13,807.0 D,F	12,853.0 D,F	12,164.0 D,F	12,430.0 D,F	10,996.0 D,F	6,497.0 F	6.7	2.4	(10.1)	191	213	198	187	191
SCG	[] SCANA CORP	DEC	4,237.0 F	5,319.0 F	4,621.0 F	4,563.0 C,F	4,777.0 F	3,885.0 F	1,650.0	9.9	1.7	(20.3)	257	322	280	277	290
SRE	[] SEMPRA ENERGY	DEC	8,106.0 F	10,758.0 F	11,438.0 D,F	11,761.0 D,F	11,737.0 D,F	9,410.0 D,F	5,360.0 F	4.2	(2.9)	(24.7)	151	201	213	219	219
TE	[] TECO ENERGY INC	DEC	3,310.5 F	3,375.3 F	3,536.1 D,F	3,448.1 D,F	3,010.1 D,F	2,669.1 D,F	1,983.0 D,F	5.3	4.4	(1.9)	167	170	178	174	152
VVC	† VECTREN CORP	DEC	2,088.9 F	2,484.7 F	2,281.9 F	2,041.6 A,F	2,028.0 F	1,689.8 F	420.5 F	17.4	4.3	(15.9)	497	591	543	486	482
WEC	[] WISCONSIN ENERGY CORP	DEC	4,127.9 D,F	4,431.0 F	4,237.8 D,F	3,996.4 D,F	3,815.5 D,F	3,431.1 D,F	2,272.6 F	6.1	3.8	(6.8)	182	195	186	176	168
XEL	[] XCEL ENERGY INC	DEC	9,644.3 D,F	11,203.2 D,F	10,034.2 D,F	9,840.3 D,F	9,625.5 D,F	8,345.3 D,F	2,869.0	12.9	2.9	(13.9)	336	390	350	343	335
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AES	[] AES CORP	DEC	14,119.0 D	16,102.0 D	13,588.0 D	11,564.0 D	11,086.0	9,463.0	3,253.0 A	15.8	8.3	(12.3)	434	495	418	355	341
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	15,598.8 F	19,818.3 F	21,193.2 A,C	19,284.9 D,F	17,132.0 C,D	12,549.7 A,C	3,786.2 F	15.2	4.4	(21.3)	412	523	560	509	452
DYN	† DYNEGY INC	DEC	2,468.0 D	3,549.0	3,072.0 A,C	2,017.0 A	2,313.0 A,C	6,153.0	15,430.0	(16.7)	(16.7)	(30.5)	16	23	20	13	15
NRG	[] NRG ENERGY INC	DEC	8,952.0 A,F	6,885.0 D,F	5,989.0 D,F	5,623.0 D,F	2,708.0 D,F	2,361.4 D,F	432.5 A	35.4	30.5	30.0	2,070	1,592	1,385	1,300	626
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	8,570.9	7,041.7 A	8,934.3 A	6,453.8 D	5,253.9	4,243.8 A,C	8,252.5 D,F	0.4	15.1	21.7	104	85	108	78	64

Note: Data as originally reported. CAGR-Compound annual growth rate. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year. **Not calculated; data for base year or end year not available. A - This year's data reflect an acquisition or merger. B - This year's data reflect a major merger resulting in the formation of a new company. C - This year's data reflect an accounting change. D - Data exclude discontinued operations. E - Includes excise taxes. F - Includes other (nonoperating) income. G - Includes sale of leased depts. H - Some or all data are not available, due to a fiscal year change.

Net Income

Ticker	Company	Yr. End	Million $ 2009	2008	2007	2006	2005	2004	1999	CAGR (%) 10-Yr.	5-Yr.	1-Yr.	Index Basis (1999 = 100) 2009	2008	2007	2006	2005
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	222.0	217.0	211.0	212.0	193.0	153.0	80.5	10.7	7.7	2.3	276	270	262	263	240
ATO	† ATMOS ENERGY CORP	SEP	191.0	180.3	168.5	147.7	135.8	86.2	17.7	26.8	17.2	5.9	1,076	1,016	950	833	765
EGN	† ENERGEN CORP	DEC	256.3	321.9	309.2	273.5	172.9	127.4	41.4	20.0	15.0	(20.4)	619	777	747	661	417
EQT	[] EQT CORP	DEC	156.9	255.6	257.5	216.0	258.6	279.9	69.1	8.5	(10.9)	(38.6)	227	370	372	312	374
LG	§ LACLEDE GROUP INC	SEP	64.3	57.6	49.8	49.0	40.1	36.1	26.1	9.4	12.2	11.6	247	221	191	188	154
NFG	† NATIONAL FUEL GAS CO	SEP	100.7	268.7	201.7	138.1	153.5	166.6	115.0	(1.3)	(9.6)	(62.5)	88	234	175	120	133
NJR	§ NEW JERSEY RESOURCES CORP	SEP	27.2	113.9	65.3	78.5	76.3	71.6	44.9	(4.9)	(17.6)	(76.1)	61	254	145	175	170
GAS	[] NICOR INC	DEC	135.5	119.5	135.2	128.3	136.3	75.1	124.4	0.9	12.5	13.4	109	96	109	103	110
NWN	§ NORTHWEST NATURAL GAS CO	DEC	75.1	69.5	74.5	63.4	58.1	50.6	44.9	5.3	8.2	8.1	167	155	166	141	129
OKE	[] ONEOK INC	DEC	305.5	311.9	304.9	306.7	403.1	242.2	106.4	11.1	4.8	(2.1)	287	293	287	288	379
PNY	§ PIEDMONT NATURAL GAS CO	OCT	122.8	110.0	104.4	97.2	101.3	95.2	58.2	7.8	5.2	11.7	211	189	179	167	174
STR	[] QUESTAR CORP	DEC	393.3	683.8	507.4	444.1	325.7	229.3	98.8	14.8	11.4	(42.5)	398	692	513	449	330
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	58.5	77.2	62.7	72.3	48.6	43.0	22.0	10.3	6.4	(24.2)	266	351	285	329	221
SWX	§ SOUTHWEST GAS CORP	DEC	87.5	61.0	83.2	83.9	43.8	56.8	39.3	8.3	9.0	43.5	223	155	212	213	111
UGI	† UGI CORP	SEP	258.5	215.5	204.3	176.2	187.5	111.6	57.3	16.3	18.3	20.0	451	376	357	308	327
WGL	† WGL HOLDINGS INC	SEP	121.7	117.8	109.2	96.0	104.8	98.0	68.8	5.9	4.4	3.3	177	171	159	140	152
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	129.4	298.7	443.4	357.0	75.1	229.5	203.3	(4.4)	(10.8)	(56.7)	64	147	218	176	37
AEE	[] AMEREN CORP	DEC	612.0	615.0	629.0	558.0	641.0	541.0	397.7	4.4	2.5	(0.5)	154	155	158	140	161
AVA	§ AVISTA CORP	DEC	87.1	73.6	38.5	73.1	45.2	35.6	26.0	12.8	19.6	18.3	334	283	148	281	174
BKH	† BLACK HILLS CORP	DEC	78.8	(52.2)	100.1	74.0	35.8	57.2	37.1	7.8	6.6	NM	212	(141)	270	200	96
CNP	[] CENTERPOINT ENERGY INC	DEC	372.0	447.0	399.0	432.0	225.0	205.7	1,665.7	(13.9)	12.6	(16.8)	22	27	24	26	14
CHG	§ CH ENERGY GROUP INC	DEC	34.6	36.1	43.6	44.1	45.3	43.4	51.8	(4.0)	(4.4)	(4.0)	67	70	84	85	87
CMS	[] CMS ENERGY CORP	DEC	209.0	300.0	(124.0)	(80.0)	(93.0)	132.0	283.0	(3.0)	9.6	(30.3)	74	106	(44)	(28)	(33)
ED	[] CONSOLIDATED EDISON INC	DEC	879.0	933.0	936.0	749.0	743.0	560.0	714.2	2.1	9.4	(5.8)	123	131	131	105	104
D	[] DOMINION RESOURCES INC	DEC	1,304.0	1,853.0	2,721.0	1,579.0	1,050.0	1,280.0	551.0	9.0	0.4	(29.6)	237	336	494	287	191
DTE	[] DTE ENERGY CO	DEC	532.0	526.0	787.0	437.0	576.0	443.0	483.0	1.0	3.7	1.1	110	109	163	90	119
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	(70.6)	124.8	181.1	151.6	162.1	156.2	62.7	NM	NM	NM	(113)	199	289	242	259
MDU	† MDU RESOURCES GROUP INC	DEC	(123.3)	293.7	322.8	317.9	275.1	207.1	84.1	NM	NM	NM	(147)	349	384	378	327
NI	[] NISOURCE INC	DEC	231.2	369.8	312.0	314.6	287.8	434.6	168.7	3.2	(11.9)	(37.5)	137	219	185	186	171
NWE	§ NORTHWESTERN CORP	DEC	73.4	67.6	53.2	37.5	61.5	542.4	38.1	6.8	(33.0)	8.6	193	178	140	98	162
NST	† NSTAR	DEC	246.0	239.5	223.5	208.7	198.1	190.4	146.5	5.3	5.3	2.7	168	164	153	143	135
OGE	† OGE ENERGY CORP	DEC	258.3	231.4	244.2	226.1	166.1	153.0	151.3	5.5	11.0	11.6	171	153	161	149	110
PCG	[] PG&E CORP	DEC	1,234.0	1,184.0	1,006.0	991.0	904.0	3,820.0	38.0	41.6	(20.2)	4.2	3,247	3,116	2,647	2,608	2,379
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	1,592.0	987.0	1,323.0	756.0	862.0	725.0	732.0	8.1	17.0	61.3	217	135	181	103	118
SCG	[] SCANA CORP	DEC	357.0	353.0	327.0	311.0	327.0	264.0	186.0	6.7	6.2	1.1	192	190	176	167	176
SRE	[] SEMPRA ENERGY	DEC	1,129.0	1,123.0	1,135.0	1,101.0	939.0	930.0	405.0	10.8	4.0	0.5	279	277	280	272	232
TE	[] TECO ENERGY INC	DEC	213.9	162.4	398.9	244.4	211.0	(404.4)	200.9	0.6	NM	31.7	106	81	199	122	105
VVC	† VECTREN CORP	DEC	133.1	129.0	143.1	108.8	136.8	107.9	41.8	12.3	4.3	3.2	319	309	343	261	328
WEC	[] WISCONSIN ENERGY CORP	DEC	377.2	358.6	336.5	312.5	303.6	122.2	210.2	6.0	25.3	5.2	179	171	160	149	144
XEL	[] XCEL ENERGY INC	DEC	685.5	645.7	575.9	568.7	499.0	526.9	224.3	11.8	5.4	6.2	306	288	257	253	222
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AES	[] AES CORP	DEC	729.0	1,216.0	495.0	135.0	632.0	258.0	245.0	11.5	23.1	(40.0)	298	496	202	55	258
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	4,503.4	(1,301.2)	835.6	761.8	619.9	602.0	339.9	29.5	49.6	NM	1,325	(383)	246	224	182
DYN	† DYNEGY INC	DEC	(1,025.0)	171.0	116.0	(358.0)	(804.0)	(10.0)	151.8	NM	NM	NM	(675)	113	76	(236)	(529)
NRG	[] NRG ENERGY INC	DEC	942.0	1,016.0	569.0	555.0	77.0	162.1	57.2	32.3	42.2	(7.3)	1,647	1,776	995	970	135
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	1,340.2	1,194.4	1,260.0	920.9	1,056.1	832.6	382.3	13.4	10.0	12.2	351	312	330	241	276

Note: Data as originally reported. CAGR-Compound annual growth rate. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600.
#Of the following calendar year. **Not calculated; data for base year or end year not available.

			Return on Revenues (%)					Return on Assets (%)					Return on Equity (%)				
Ticker	Company	Yr. End	2009	2008	2007	2006	2005	2009	2008	2007	2006	2005	2009	2008	2007	2006	2005
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	9.6	7.8	8.5	8.1	7.1	3.2	3.3	3.4	3.4	3.2	12.9	13.1	12.9	13.6	13.4
ATO	† ATMOS ENERGY CORP	SEP	3.8	2.5	2.9	2.4	2.7	3.0	2.9	2.9	2.6	3.2	9.0	9.0	9.3	9.1	9.9
EGN	† ENERGEN CORP	DEC	17.9	20.5	21.5	20.4	15.3	6.8	9.4	10.5	10.0	7.2	13.1	19.6	24.0	26.1	20.4
EQT	[] EQT CORP	DEC	12.4	16.2	18.9	17.0	20.6	2.8	5.5	7.2	6.5	7.9	7.5	16.2	25.2	33.2	42.1
LG	§ LACLEDE GROUP INC	SEP	3.4	2.6	2.5	2.5	2.5	3.6	3.4	3.1	3.3	3.0	12.8	12.6	12.0	12.7	11.1
NFG	† NATIONAL FUEL GAS CO	SEP	4.9	11.2	9.9	6.0	8.0	2.3	6.7	5.3	3.7	4.1	6.3	16.6	13.1	10.3	12.4
NJR	§ NEW JERSEY RESOURCES CORP	SEP	1.1	3.0	2.2	2.4	2.4	1.1	4.7	2.8	3.4	3.8	3.8	16.6	10.3	14.8	16.9
GAS	[] NICOR INC	DEC	5.1	3.2	4.3	4.3	4.1	2.9	2.6	3.2	3.0	3.3	13.5	12.5	14.9	15.2	17.5
NWN	§ NORTHWEST NATURAL GAS CO	DEC	7.4	6.7	7.2	6.3	6.4	3.1	3.2	3.8	3.2	3.1	11.7	11.4	12.5	10.7	10.1
OKE	[] ONEOK INC	DEC	2.7	1.9	2.3	2.6	3.2	2.4	2.6	2.8	3.0	4.7	14.2	15.4	14.6	15.3	23.7
PNY	§ PIEDMONT NATURAL GAS CO	OCT	7.5	5.3	6.1	5.0	5.8	4.0	3.7	3.8	3.6	4.1	13.5	12.5	11.9	11.0	11.6
STR	[] QUESTAR CORP	DEC	12.9	19.7	18.6	15.7	12.0	4.5	9.4	9.2	9.4	8.1	11.4	22.8	21.2	23.7	21.8
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	6.9	8.0	6.6	7.8	5.3	3.3	4.6	4.0	4.8	3.6	11.1	15.5	13.6	17.3	13.2
SWX	§ SOUTHWEST GAS CORP	DEC	4.6	2.8	3.9	4.1	2.6	2.3	1.6	2.3	2.5	1.4	8.2	6.0	8.8	10.1	6.0
UGI	† UGI CORP	SEP	4.5	3.2	3.7	3.4	3.8	4.4	3.9	3.9	3.7	4.3	17.2	15.7	16.9	16.8	20.5
WGL	† WGL HOLDINGS INC	SEP	4.5	4.5	4.1	3.6	7.6	3.7	3.7	3.7	3.5	4.1	11.2	11.5	11.3	10.4	11.8
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	3.8	8.1	12.9	10.6	2.3	1.3	3.6	6.0	4.6	0.7	4.0	10.2	15.9	13.3	2.3
AEE	[] AMEREN CORP	DEC	8.6	7.8	8.3	8.1	9.5	2.6	2.8	3.1	2.9	3.5	8.3	8.8	9.3	8.4	10.3
AVA	§ AVISTA CORP	DEC	5.8	4.4	2.7	4.9	3.3	2.4	2.2	1.1	1.6	1.0	8.5	7.7	4.2	8.7	5.9
BKH	† BLACK HILLS CORP	DEC	6.2	NM	14.4	11.3	2.6	2.4	NM	4.2	3.4	1.7	7.4	NM	11.4	9.7	4.9
CNP	[] CENTERPOINT ENERGY INC	DEC	4.5	3.9	4.1	4.6	2.3	1.9	2.4	2.2	2.5	1.3	15.9	23.2	23.7	30.3	18.7
CHG	§ CH ENERGY GROUP INC	DEC	3.7	2.7	3.6	4.4	4.7	2.0	2.2	2.9	3.0	3.3	6.4	6.7	8.2	8.5	8.9
CMS	[] CMS ENERGY CORP	DEC	3.4	4.4	NM	NM	NM	1.3	2.0	NM	NM	NM	7.8	12.6	NM	NM	NM
ED	[] CONSOLIDATED EDISON INC	DEC	6.7	6.9	7.1	6.2	6.4	2.6	3.0	3.4	2.9	3.1	8.7	9.8	10.8	9.6	10.2
D	[] DOMINION RESOURCES INC	DEC	8.6	11.4	17.4	9.6	5.8	3.0	4.5	6.1	3.1	2.1	12.1	18.8	24.2	13.4	9.5
DTE	[] DTE ENERGY CO	DEC	6.6	5.6	9.3	4.8	6.4	2.2	2.2	3.3	1.9	2.6	8.7	8.9	13.5	7.5	10.2
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	NM	0.9	1.8	2.2	2.3	NM	1.0	2.0	2.4	3.2	NM	3.8	7.5	10.5	13.3
MDU	† MDU RESOURCES GROUP INC	DEC	NM	5.9	7.6	7.8	8.0	NM	4.8	6.1	6.8	6.7	NM	11.1	13.8	15.8	15.5
NI	[] NISOURCE INC	DEC	3.5	4.2	3.9	4.2	3.6	1.2	1.9	1.7	1.7	1.6	4.8	7.5	6.2	6.3	5.8
NWE	§ NORTHWESTERN CORP	DEC	6.4	5.4	4.4	3.3	5.3	2.6	2.5	2.2	1.6	2.6	9.5	8.5	6.8	5.1	8.5
NST	† NSTAR	DEC	8.1	7.2	6.9	5.8	6.1	3.0	3.0	2.9	2.7	2.7	13.3	13.6	13.5	13.3	13.2
OGE	† OGE ENERGY CORP	DEC	9.0	5.7	6.4	5.6	2.8	3.7	3.9	4.8	4.6	3.4	13.1	12.9	14.9	15.2	12.5
PCG	[] PG&E CORP	DEC	9.2	8.1	7.6	7.9	7.7	2.9	3.1	2.8	2.9	2.6	12.4	13.2	12.3	13.2	11.4
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	12.8	7.1	10.3	6.2	6.9	5.5	3.4	4.6	2.6	2.9	19.2	13.0	18.8	11.8	14.6
SCG	[] SCANA CORP	DEC	8.4	6.6	7.1	6.8	6.8	2.9	3.2	3.2	3.1	3.5	10.8	11.5	11.0	11.0	12.5
SRE	[] SEMPRA ENERGY	DEC	13.9	10.4	9.9	9.4	8.0	4.1	3.9	3.8	3.8	3.5	13.2	13.6	14.2	16.0	16.9
TE	[] TECO ENERGY INC	DEC	6.5	4.8	11.3	7.1	7.0	3.0	2.3	5.6	3.4	2.5	10.5	8.1	21.3	14.7	14.7
VVC	† VECTREN CORP	DEC	6.4	5.2	6.3	5.3	6.7	2.9	2.9	3.4	2.7	3.7	9.7	10.0	11.9	9.4	12.2
WEC	[] WISCONSIN ENERGY CORP	DEC	9.1	8.1	7.9	7.8	8.0	3.0	2.9	2.9	2.9	3.0	10.9	11.1	11.2	11.2	11.7
XEL	[] XCEL ENERGY INC	DEC	7.1	5.8	5.7	5.8	5.2	2.7	2.7	2.5	2.6	2.4	9.6	9.7	9.4	10.1	9.3
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AES	[] AES CORP	DEC	5.2	7.6	3.6	1.2	5.7	2.0	3.5	1.5	0.4	2.2	17.5	35.6	16.2	5.9	48.2
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	28.9	NM	3.9	4.0	3.6	19.4	NM	3.8	3.5	3.1	74.8	NM	16.5	15.7	12.6
DYN	† DYNEGY INC	DEC	NM	4.8	3.8	NM	NM	NM	1.2	1.1	NM	NM	NM	3.8	3.4	NM	NM
NRG	[] NRG ENERGY INC	DEC	10.5	14.8	9.5	9.9	2.8	3.8	4.4	2.7	3.8	0.7	13.2	17.7	11.0	15.3	2.8
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	15.6	17.0	14.1	14.3	20.1	3.5	3.7	4.7	4.2	5.3	10.5	11.5	15.0	14.1	17.8

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

Ticker	Company	Yr. End	Current Ratio 2009	2008	2007	2006	2005	Debt / Capital Ratio (%) 2009	2008	2007	2006	2005	Debt as a % of Net Working Capital 2009	2008	2007	2006	2005
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	1.1	1.0	1.1	1.1	1.0	43.9	42.5	42.2	42.3	44.9	865.8	NM	NM	831.8	NM
ATO	† ATMOS ENERGY CORP	SEP	1.1	1.1	1.2	1.0	1.1	49.9	50.8	52.0	57.0	57.7	NM	NM	NM	NM	NM
EGN	† ENERGEN CORP	DEC	1.0	1.3	0.7	0.9	0.7	17.1	22.7	29.0	32.6	43.4	NM	422.5	NM	NM	NM
EQT	[] EQT CORP	DEC	1.1	0.9	0.5	0.6	0.5	47.5	37.9	40.7	44.3	68.3	NM	NM	NM	NM	NM
LG	§ LACLEDE GROUP INC	SEP	1.2	1.2	1.0	1.1	1.2	33.4	35.3	35.1	38.2	37.9	558.9	470.6	NM	NM	581.3
NFG	† NATIONAL FUEL GAS CO	SEP	2.4	1.3	1.3	1.8	1.2	35.6	30.8	26.5	35.5	39.3	272.4	799.8	696.0	478.2	991.9
NJR	§ NEW JERSEY RESOURCES CORP	SEP	1.2	1.2	1.1	1.1	1.0	32.6	31.8	30.6	28.0	36.5	355.8	211.0	396.7	486.1	NM
GAS	[] NICOR INC	DEC	0.9	0.8	0.8	0.8	0.8	25.3	24.3	23.6	27.7	27.8	NM	NM	NM	NM	NM
NWN	§ NORTHWEST NATURAL GAS CO	DEC	0.8	0.9	0.7	0.9	1.0	47.7	44.9	46.3	46.3	39.0	NM	NM	NM	NM	NM
OKE	[] ONEOK INC	DEC	0.8	0.8	1.0	1.6	0.9	55.7	56.5	60.3	57.2	53.0	NM	NM	NM	343.2	NM
PNY	§ PIEDMONT NATURAL GAS CO	OCT	0.9	0.9	1.0	1.2	1.0	35.9	39.9	41.8	42.4	36.2	NM	NM	NM	NM	NM
STR	[] QUESTAR CORP	DEC	0.9	1.0	0.7	1.1	0.9	29.9	30.3	22.5	25.6	31.1	NM	NM	NM	NM	NM
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	0.8	0.9	1.0	0.9	0.9	29.1	32.1	35.2	36.5	36.1	NM	NM	NM	NM	NM
SWX	§ SOUTHWEST GAS CORP	DEC	0.9	0.9	1.0	1.0	0.9	53.5	55.3	58.1	60.6	63.8	NM	NM	NM	NM	NM
UGI	† UGI CORP	SEP	1.1	1.1	1.1	1.0	1.0	46.7	48.9	50.1	53.1	45.2	NM	NM	NM	NM	NM
WGL	† WGL HOLDINGS INC	SEP	1.1	1.0	1.0	1.0	1.2	27.8	30.8	32.4	31.4	32.2	NM	NM	NM	NM	840.3
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	1.3	1.4	1.6	1.1	1.1	44.3	36.3	32.4	31.3	37.0	793.0	429.1	262.4	NM	942.8
AEE	[] AMEREN CORP	DEC	1.7	0.8	0.9	0.9	1.2	42.6	41.1	38.5	36.9	38.3	702.3	NM	NM	NM	NM
AVA	§ AVISTA CORP	DEC	0.8	0.7	0.4	1.1	1.0	50.1	48.1	41.0	53.7	59.4	NM	NM	NM	NM	NM
BKH	† BLACK HILLS CORP	DEC	1.0	0.6	0.9	0.9	1.2	48.4	32.3	36.7	44.1	47.4	NM	NM	NM	NM	939.4
CNP	[] CENTERPOINT ENERGY INC	DEC	1.0	1.1	0.7	0.7	1.0	62.7	68.6	67.2	66.6	69.2	NM	NM	NM	NM	NM
CHG	§ CH ENERGY GROUP INC	DEC	1.5	1.3	1.5	1.4	2.2	45.5	43.1	42.5	38.7	39.6	489.6	622.2	411.7	450.4	211.3
CMS	[] CMS ENERGY CORP	DEC	1.4	1.5	1.2	1.5	1.8	65.4	68.3	69.5	69.5	68.7	773.1	647.6	NM	650.7	408.0
ED	[] CONSOLIDATED EDISON INC	DEC	1.1	1.0	0.7	1.0	0.9	38.1	38.3	35.6	40.3	39.7	NM	NM	NM	NM	NM
D	[] DOMINION RESOURCES INC	DEC	1.0	1.0	0.9	0.7	0.7	57.5	59.1	57.7	43.7	48.4	NM	NM	NM	NM	NM
DTE	[] DTE ENERGY CO	DEC	1.1	1.1	0.9	1.0	1.0	46.4	48.9	47.1	50.0	48.9	NM	NM	NM	NM	NM
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	1.1	1.0	1.1	1.0	1.1	39.9	38.7	37.2	43.1	37.8	656.8	NM	473.8	NM	492.7
MDU	† MDU RESOURCES GROUP INC	DEC	1.6	1.3	1.4	1.5	1.5	36.6	36.2	31.2	35.1	36.9	376.9	514.6	314.7	344.5	363.1
NI	[] NISOURCE INC	DEC	0.7	0.7	0.7	0.7	0.8	46.3	48.4	45.5	43.7	44.1	NM	NM	NM	NM	NM
NWE	§ NORTHWESTERN CORP	DEC	0.9	0.5	0.9	1.0	0.7	56.4	46.8	50.1	49.9	44.3	NM	NM	NM	NM	NM
NST	† NSTAR	DEC	0.7	0.8	0.9	0.8	0.9	38.3	44.0	46.5	45.2	60.4	NM	NM	NM	NM	NM
OGE	† OGE ENERGY CORP	DEC	0.6	0.8	0.6	1.0	1.1	38.6	42.6	34.5	35.1	37.9	NM	NM	NM	NM	NM
PCG	[] PG&E CORP	DEC	0.8	0.8	0.8	0.7	0.9	51.4	44.5	44.9	44.0	47.2	NM	NM	NM	NM	NM
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	1.1	1.2	1.1	1.1	1.0	46.3	50.5	54.0	60.3	64.9	NM	NM	NM	NM	NM
SCG	[] SCANA CORP	DEC	1.2	1.6	0.8	1.0	1.0	49.1	50.5	41.1	43.2	43.4	NM	640.4	NM	NM	NM
SRE	[] SEMPRA ENERGY	DEC	0.6	0.7	1.1	1.2	1.1	41.1	41.4	33.5	36.5	42.8	NM	NM	493.1	281.2	429.4
TE	[] TECO ENERGY INC	DEC	0.8	1.0	1.3	1.0	1.4	60.6	61.5	61.0	65.0	70.0	NM	NM	NM	NM	NM
VVC	† VECTREN CORP	DEC	0.8	0.7	0.7	0.7	0.9	45.3	42.2	44.4	45.5	51.2	NM	NM	NM	NM	NM
WEC	[] WISCONSIN ENERGY CORP	DEC	0.8	1.0	0.7	0.7	0.8	45.4	49.1	46.0	46.4	47.4	NM	NM	NM	NM	NM
XEL	[] XCEL ENERGY INC	DEC	0.9	1.0	0.8	0.9	0.9	42.2	43.7	41.1	43.7	43.0	NM	NM	NM	NM	NM
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AES	[] AES CORP	DEC	1.3	1.4	1.5	1.3	1.0	64.1	67.3	68.7	68.5	80.0	828.4	788.9	584.4	952.3	NM
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	1.8	1.0	1.3	1.3	1.3	28.3	55.4	39.3	39.8	40.7	140.8	NM	229.4	213.5	282.0
DYN	† DYNEGY INC	DEC	1.1	1.6	1.7	1.7	1.8	56.0	51.8	50.7	53.8	57.7	NM	551.5	894.4	387.6	265.9
NRG	[] NRG ENERGY INC	DEC	1.7	1.3	1.6	1.5	1.6	44.7	47.4	54.5	57.2	49.7	320.8	403.1	614.4	822.7	306.9
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	0.6	0.7	0.8	0.7	0.5	47.6	53.3	54.3	57.4	56.1	NM	NM	NM	NM	NM

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

			Price / Earnings Ratio (High-Low)					Dividend Payout Ratio (%)					Dividend Yield (High-Low, %)				
Ticker	Company	Yr. End	2009	2008	2007	2006	2005	2009	2008	2007	2006	2005	2009	2008	2007	2006	2005
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	13 - 8	14 - 8	16 - 13	15 - 13	16 - 13	60	59	60	54	52	7.2 - 4.6	7.0 - 4.3	4.7 - 3.7	4.3 - 3.7	4.1 - 3.3
ATO	† ATMOS ENERGY CORP	SEP	14 - 10	15 - 10	17 - 12	18 - 14	17 - 14	63	64	66	69	72	6.6 - 4.4	6.6 - 4.4	5.4 - 3.8	4.9 - 3.8	5.0 - 4.1
EGN	† ENERGEN CORP	DEC	14 - 6	18 - 5	16 - 10	13 - 9	19 - 11	14	11	11	12	17	2.2 - 1.0	2.1 - 0.6	1.1 - 0.7	1.4 - 0.9	1.5 - 0.9
EQT	[] EQT CORP	DEC	39 - 23	38 - 10	27 - 19	25 - 18	19 - 13	73	44	42	49	38	3.2 - 1.9	4.2 - 1.2	2.2 - 1.6	2.8 - 2.0	2.9 - 2.0
LG	§ LACLEDE GROUP INC	SEP	16 - 10	21 - 12	16 - 12	16 - 13	18 - 14	53	56	63	61	72	5.3 - 3.2	4.7 - 2.7	5.1 - 4.1	4.8 - 3.8	5.1 - 4.0
NFG	† NATIONAL FUEL GAS CO	SEP	41 - 21	19 - 8	21 - 15	25 - 19	20 - 14	105	39	50	72	62	4.9 - 2.5	4.7 - 2.0	3.3 - 2.4	3.9 - 2.9	4.4 - 3.2
NJR	§ NEW JERSEY RESOURCES CORP	SEP	65 - 46	15 - 8	24 - 19	19 - 15	18 - 15	191	41	65	51	49	4.1 - 2.9	5.1 - 2.7	3.3 - 2.7	3.5 - 2.7	3.3 - 2.8
GAS	[] NICOR INC	DEC	15 - 9	20 - 12	18 - 13	17 - 13	14 - 12	62	70	62	65	60	6.8 - 4.3	5.7 - 3.6	4.9 - 3.5	4.8 - 3.7	5.2 - 4.3
NWN	§ NORTHWEST NATURAL GAS CO	DEC	16 - 13	21 - 14	19 - 14	19 - 14	19 - 15	57	58	52	60	63	4.2 - 3.4	4.2 - 2.8	3.6 - 2.7	4.2 - 3.2	4.1 - 3.3
OKE	[] ONEOK INC	DEC	16 - 6	17 - 7	19 - 14	16 - 10	9 - 7	57	52	49	45	27	9.1 - 3.6	7.2 - 3.0	3.6 - 2.5	4.6 - 2.7	4.1 - 3.0
PNY	§ PIEDMONT NATURAL GAS CO	OCT	19 - 12	24 - 14	20 - 16	22 - 18	20 - 16	64	69	70	74	69	5.2 - 3.3	5.0 - 2.9	4.5 - 3.5	4.1 - 3.3	4.3 - 3.5
STR	[] QUESTAR CORP	DEC	19 - 11	19 - 5	20 - 13	18 - 13	23 - 12	22	12	16	18	23	2.0 - 1.2	2.4 - 0.7	1.3 - 0.8	1.4 - 1.0	1.9 - 1.0
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	21 - 16	16 - 10	19 - 15	14 - 10	19 - 15	62	43	47	37	50	3.8 - 3.0	4.4 - 2.7	3.2 - 2.4	3.6 - 2.7	3.5 - 2.7
SWX	§ SOUTHWEST GAS CORP	DEC	15 - 9	24 - 15	20 - 13	19 - 13	24 - 20	48	64	43	40	71	5.5 - 3.2	4.2 - 2.7	3.2 - 2.1	3.1 - 2.1	3.5 - 2.9
UGI	† UGI CORP	SEP	12 - 9	14 - 9	15 - 12	17 - 12	17 - 11	33	38	38	41	36	3.7 - 2.9	4.0 - 2.6	3.2 - 2.4	3.3 - 2.4	3.4 - 2.2
WGL	† WGL HOLDINGS INC	SEP	15 - 12	16 - 10	16 - 14	17 - 14	16 - 14	60	59	62	69	62	5.1 - 4.1	6.2 - 3.8	4.6 - 3.8	5.0 - 4.0	4.6 - 3.8
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	31 - 20	17 - 9	12 - 9	14 - 10	64 - 53	149	55	34	40	219	7.4 - 4.8	6.1 - 3.3	3.6 - 2.7	4.1 - 2.9	4.1 - 3.4
AEE	[] AMEREN CORP	DEC	13 - 7	19 - 9	18 - 16	21 - 18	18 - 15	55	88	85	95	81	7.9 - 4.4	10.0 - 4.7	5.4 - 4.6	5.3 - 4.6	5.3 - 4.5
AVA	§ AVISTA CORP	DEC	14 - 8	17 - 11	35 - 25	18 - 12	22 - 18	51	50	82	38	59	6.4 - 3.6	4.4 - 2.9	3.3 - 2.3	3.2 - 2.1	3.3 - 2.7
BKH	† BLACK HILLS CORP	DEC	14 - 7	NM - NM	17 - 13	17 - 15	41 - 27	70	NM	51	59	117	9.8 - 5.1	6.4 - 3.2	3.9 - 3.0	4.1 - 3.5	4.4 - 2.9
CNP	[] CENTERPOINT ENERGY INC	DEC	15 - 8	13 - 6	16 - 12	12 - 8	21 - 15	75	55	54	43	56	8.8 - 5.1	8.6 - 4.2	4.6 - 3.4	5.2 - 3.6	3.8 - 2.6
CHG	§ CH ENERGY GROUP INC	DEC	25 - 18	24 - 15	20 - 15	20 - 16	18 - 15	101	97	80	79	77	5.7 - 4.1	6.5 - 4.1	5.2 - 4.0	4.8 - 3.9	5.1 - 4.3
CMS	[] CMS ENERGY CORP	DEC	19 - 11	14 - 6	NM - NM	NM - NM	NM - NM	57	28	NM	NM	NM	5.0 - 3.1	4.3 - 2.1	1.3 - 1.0	0.0 - 0.0	0.0 - 0.0
ED	[] CONSOLIDATED EDISON INC	DEC	15 - 10	15 - 10	15 - 12	17 - 14	16 - 14	75	69	67	78	76	7.2 - 5.1	6.9 - 4.7	5.4 - 4.4	5.6 - 4.7	5.5 - 4.6
D	[] DOMINION RESOURCES INC	DEC	18 - 13	15 - 10	12 - 10	19 - 15	29 - 22	81	50	35	62	89	6.4 - 4.4	5.1 - 3.3	3.7 - 3.0	4.0 - 3.3	4.0 - 3.1
DTE	[] DTE ENERGY CO	DEC	14 - 7	14 - 9	12 - 9	20 - 16	15 - 13	65	65	46	84	63	9.1 - 4.7	7.6 - 4.7	4.8 - 3.9	5.4 - 4.2	5.0 - 4.3
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	NM - NM	34 - 23	24 - 19	16 - 14	14 - 11	NM	169	101	65	54	14.0 - 6.0	7.3 - 5.0	5.2 - 4.1	4.8 - 3.9	4.7 - 3.7
MDU	† MDU RESOURCES GROUP INC	DEC	NM - NM	22 - 10	18 - 14	15 - 12	16 - 11	NM	38	32	30	32	4.9 - 2.6	3.9 - 1.7	2.3 - 1.8	2.4 - 1.9	2.9 - 2.0
NI	[] NISOURCE INC	DEC	19 - 9	15 - 8	22 - 15	22 - 17	24 - 19	110	68	81	80	88	11.8 - 5.8	8.9 - 4.6	5.3 - 3.6	4.7 - 3.7	4.5 - 3.6
NWE	§ NORTHWESTERN CORP	DEC	13 - 9	17 - 9	25 - 17	34 - 28	19 - 15	66	74	88	117	58	7.3 - 5.0	8.0 - 4.4	5.2 - 3.5	4.1 - 3.5	3.9 - 3.1
NST	† NSTAR	DEC	17 - 12	18 - 12	18 - 15	19 - 14	17 - 14	66	63	63	62	63	5.5 - 4.0	5.5 - 3.5	4.2 - 3.5	4.6 - 3.4	4.7 - 3.7
OGE	† OGE ENERGY CORP	DEC	14 - 7	14 - 8	16 - 11	16 - 11	17 - 13	53	56	51	54	72	7.2 - 3.8	7.1 - 3.8	4.7 - 3.3	5.0 - 3.3	5.4 - 4.3
PCG	[] PG&E CORP	DEC	14 - 10	14 - 8	18 - 15	17 - 13	17 - 13	51	47	50	46	51	4.9 - 3.7	5.8 - 3.4	3.4 - 2.8	3.6 - 2.7	3.9 - 3.1
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	11 - 8	27 - 11	19 - 12	24 - 20	19 - 14	42	66	45	76	63	5.6 - 3.9	5.8 - 2.5	3.6 - 2.3	3.9 - 3.1	4.5 - 3.3
SCG	[] SCANA CORP	DEC	14 - 9	15 - 9	17 - 12	16 - 14	16 - 13	66	62	64	64	56	7.2 - 4.9	6.6 - 4.2	5.3 - 3.9	4.6 - 4.0	4.3 - 3.6
SRE	[] SEMPRA ENERGY	DEC	12 - 8	14 - 8	15 - 12	13 - 10	13 - 9	34	30	29	28	31	4.3 - 2.7	4.0 - 2.2	2.4 - 1.9	2.8 - 2.1	3.3 - 2.4
TE	[] TECO ENERGY INC	DEC	17 - 8	29 - 14	10 - 8	15 - 12	19 - 15	80	103	41	64	75	9.5 - 4.8	7.6 - 3.6	5.2 - 4.2	5.3 - 4.3	5.1 - 3.9
VVC	† VECTREN CORP	DEC	16 - 11	20 - 12	16 - 13	20 - 18	16 - 14	82	79	67	85	66	7.4 - 5.0	6.7 - 4.1	5.1 - 4.2	4.9 - 4.2	4.8 - 4.0
WEC	[] WISCONSIN ENERGY CORP	DEC	16 - 11	16 - 11	18 - 14	18 - 14	16 - 13	42	35	35	34	34	3.7 - 2.7	3.1 - 2.2	2.4 - 2.0	2.4 - 1.9	2.6 - 2.2
XEL	[] XCEL ENERGY INC	DEC	15 - 11	16 - 10	18 - 14	17 - 13	16 - 13	65	64	66	63	69	6.1 - 4.4	6.2 - 4.1	4.7 - 3.6	5.0 - 3.7	5.2 - 4.2
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AES	[] AES CORP	DEC	14 - 4	12 - 3	33 - 23	NM - 74	19 - 13	0	0	0	0	0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	2 - 1	NM - NM	23 - 15	17 - 12	18 - 13	4	NM	38	36	39	6.4 - 2.6	14.7 - 1.8	2.5 - 1.7	3.0 - 2.2	3.1 - 2.1
DYN	† DYNEGY INC	DEC	NM - NM	50 - 7	73 - 43	NM - NM	NM - NM	NM	0	0	NM	NM	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
NRG	[] NRG ENERGY INC	DEC	8 - 4	11 - 4	22 - 13	15 - 11	74 - 45	0	0	0	0	0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	17 - 10	20 - 11	19 - 13	19 - 15	15 - 11	67	65	55	61	47	6.7 - 3.9	5.7 - 3.3	4.1 - 2.9	4.1 - 3.2	4.4 - 3.1

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

			Earnings per Share ($)					Tangible Book Value per Share ($)					Share Price (High-Low, $)				
Ticker	**Company**	**Yr. End**	**2009**	**2008**	**2007**	**2006**	**2005**	**2009**	**2008**	**2007**	**2006**	**2005**	**2009**	**2008**	**2007**	**2006**	**2005**
GAS UTILITIES‡																	
AGL	† AGL RESOURCES INC	DEC	2.89	2.85	2.74	2.73	2.50	17.57	16.05	16.24	15.30	13.84	37.52 - 24.02	39.13 - 24.02	44.67 - 35.24	40.09 - 34.40	39.32 - 32.00
ATO	† ATMOS ENERGY CORP	SEP	2.10	2.02	1.94	1.83	1.73	15.52	14.46	13.75	11.13	10.74	30.32 - 20.07	29.29 - 19.68	33.47 - 23.87	33.09 - 25.55	29.97 - 25.00
EGN	† ENERGEN CORP	DEC	3.58	4.50	4.32	3.77	2.37	27.77	26.74	19.47	17.06	12.33	48.88 - 23.18	79.57 - 23.00	70.41 - 43.78	47.60 - 32.16	44.31 - 27.06
EQT	[] EQT CORP	DEC	1.20	2.01	2.12	1.79	2.14	16.43 J	15.67 J	8.98 J	7.78 J	2.96 J	46.80 - 27.39	76.14 - 20.71	56.75 - 39.26	44.48 - 31.59	41.18 - 27.89
LG	§ LACLEDE GROUP INC	SEP	2.93	2.66	2.32	2.31	1.90	23.32	22.12	18.24	17.28	15.98	48.33 - 29.26	55.81 - 31.86	36.03 - 28.84	37.51 - 29.09	34.31 - 26.90
NFG	† NATIONAL FUEL GAS CO	SEP	1.26	3.27	2.43	1.64	1.84	19.41	19.87	19.12	16.86	14.01	52.00 - 26.67	63.71 - 26.83	50.29 - 36.94	40.21 - 30.60	36.00 - 26.20
NJR	§ NEW JERSEY RESOURCES CORP	SEP	0.65	2.72	1.56	1.88	1.85	16.59	17.29	15.50	15.00	10.60	42.37 - 29.95	41.13 - 21.90	37.63 - 30.33	35.44 - 27.66	32.89 - 27.12
GAS	[] NICOR INC	DEC	2.99	2.64	2.99	2.88	3.08	22.38	21.02	20.51	19.01	18.36 J	43.39 - 27.50	51.99 - 32.35	53.66 - 37.80	49.92 - 38.72	42.97 - 35.50
NWN	§ NORTHWEST NATURAL GAS CO	DEC	2.83	2.63	2.78	2.30	2.11	24.88	23.71	22.52	21.97	21.28	46.47 - 37.71	55.23 - 36.61	52.85 - 39.79	43.69 - 32.83	39.63 - 32.42
OKE	[] ONEOK INC	DEC	2.90	2.99	2.84	2.74	4.01	11.11	10.01	8.90	10.52	11.38	44.97 - 18.10	51.33 - 21.56	55.27 - 39.26	44.48 - 26.35	35.85 - 26.30
PNY	§ PIEDMONT NATURAL GAS CO	OCT	1.68	1.50	1.41	1.28	1.32	12.00	11.45	11.18	11.07	10.91	31.98 - 20.68	35.29 - 20.52	27.98 - 22.00	28.44 - 23.21	25.80 - 21.26
STR	[] QUESTAR CORP	DEC	2.26	3.96	2.95	2.60	1.92	19.66	19.29	14.51	12.43	8.60	43.46 - 24.85	74.86 - 20.66	58.75 - 37.98	45.51 - 33.69	44.80 - 23.36
SJI	§ SOUTH JERSEY INDUSTRIES INC	DEC	1.97	2.60	2.13	2.48	1.72	18.24 J	17.33 J	16.25 J	15.11 J	13.50 J	40.78 - 31.98	40.58 - 25.19	41.27 - 31.20	34.26 - 25.63	32.38 - 24.94
SWX	§ SOUTHWEST GAS CORP	DEC	1.95	1.40	1.97	2.07	1.15	24.44	23.48	22.98	21.58	19.10	29.48 - 17.08	33.29 - 21.11	39.95 - 26.45	39.37 - 26.09	28.07 - 23.53
UGI	† UGI CORP	SEP	2.38	2.01	1.92	1.67	1.81	(1.44)	(2.10)	(3.28)	(4.57)	(3.87)	27.38 - 21.14	28.87 - 18.69	29.63 - 22.75	29.00 - 20.60	29.98 - 19.20
WGL	† WGL HOLDINGS INC	SEP	2.40	2.35	2.19	1.94	2.13	21.89	20.99	19.89	18.86	18.36	35.52 - 28.59	37.08 - 22.40	35.91 - 29.79	33.55 - 27.04	34.79 - 28.85
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	1.01	2.54	3.78	2.90	0.48	25.03	25.54	24.27	22.81	20.85	31.53 - 20.31	42.37 - 22.80	46.53 - 34.95	39.96 - 27.79	30.58 - 25.56
AEE	[] AMEREN CORP	DEC	2.78	2.88	2.98	2.66	3.13	29.04	28.10	27.47	26.80	25.12	35.35 - 19.51	54.29 - 25.51	55.00 - 47.10	55.24 - 47.96	56.77 - 47.51
AVA	§ AVISTA CORP	DEC	1.59	1.37	0.73	1.49	0.93	18.36	17.58	17.18	17.46	15.87	22.44 - 12.67	23.58 - 15.53	25.81 - 18.19	27.52 - 17.61	20.20 - 16.31
BKH	† BLACK HILLS CORP	DEC	2.04	(1.37)	2.70	2.23	1.09	18.65	17.76	24.32	22.03	20.49	27.98 - 14.54	43.98 - 21.73	45.41 - 35.40	37.95 - 32.46	44.63 - 29.19
CNP	[] CENTERPOINT ENERGY INC	DEC	1.02	1.33	1.25	1.39	0.72	2.41	0.99	0.35	(0.49)	(1.51)	14.87 - 8.66	17.35 - 8.48	20.20 - 14.70	16.87 - 11.62	15.14 - 10.55
CHG	§ CH ENERGY GROUP INC	DEC	2.13	2.22	2.70	2.73	2.81	30.56	26.61	26.90	27.44	25.63	52.66 - 37.68	52.36 - 33.39	53.79 - 41.37	54.92 - 44.63	50.23 - 42.07
CMS	[] CMS ENERGY CORP	DEC	0.87	1.29	(0.62)	(0.44)	(0.51)	11.42	10.88	9.46	9.91	10.41	16.13 - 9.98	17.47 - 8.33	19.55 - 14.98	17.00 - 12.09	16.80 - 9.70
ED	[] CONSOLIDATED EDISON INC	DEC	3.16	3.37	3.48	2.96	3.00	34.96	33.91	31.86	29.20	27.78	46.35 - 32.56	49.30 - 34.11	52.90 - 43.10	49.28 - 41.17	49.29 - 41.10
D	[] DOMINION RESOURCES INC	DEC	2.17	3.17	4.15	2.23	1.51	11.92	10.05	9.21	11.44	8.79	39.79 - 27.15	48.50 - 31.26	49.38 - 39.83	42.22 - 34.36	43.49 - 33.26
DTE	[] DTE ENERGY CO	DEC	3.24	3.24	4.64	2.46	3.29	25.39	23.85	23.22	21.00	20.88	44.96 - 23.32	45.34 - 27.82	54.74 - 43.96	49.24 - 38.77	48.31 - 41.39
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	(0.96)	1.59	2.49	3.51	4.15	28.65	28.22	29.97	28.35	31.55	45.10 - 19.44	53.92 - 36.91	60.63 - 48.10	57.75 - 47.39	60.00 - 47.67
MDU	† MDU RESOURCES GROUP INC	DEC	(0.67)	1.60	1.77	1.76	1.54	10.10	11.44	11.31	10.49	9.04	24.22 - 12.79	35.34 - 15.50	31.79 - 24.39	27.04 - 21.85	24.75 - 16.99
NI	[] NISOURCE INC	DEC	0.84	1.35	1.14	1.15	1.05	3.10	2.63	3.56	3.29	2.79	15.82 - 7.79	19.82 - 10.35	25.43 - 17.49	24.80 - 19.51	25.50 - 20.44
NWE	§ NORTHWESTERN CORP	DEC	2.03	1.78	1.45	1.06	1.73	12.00	11.37	12.01	8.63	8.49	26.85 - 18.48	29.70 - 16.47	36.66 - 24.45	35.85 - 30.07	32.53 - 25.52
NST	† NSTAR	DEC	2.28	2.22	2.07	1.94	1.84	11.93	10.95	9.98	14.82 J	8.21	37.75 - 27.49	40.00 - 25.67	37.37 - 30.75	35.90 - 26.50	31.46 - 24.90
OGE	† OGE ENERGY CORP	DEC	2.68	2.50	2.66	2.48	1.84	21.04	20.29	18.31	17.59	14.82	37.79 - 19.70	36.23 - 19.56	41.30 - 29.12	40.58 - 26.34	30.60 - 24.41
PCG	[] PG&E CORP	DEC	3.32	3.32	2.87	2.86	2.43	27.69	25.80	24.00	22.31	21.09	45.79 - 34.50	45.68 - 26.67	52.17 - 42.58	48.17 - 36.25	40.10 - 31.83
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	3.15	1.94	2.60	1.50	1.78	17.09	15.22	14.23	12.19	10.78	34.14 - 23.65	52.30 - 22.09	49.88 - 32.16	36.31 - 29.50	34.24 - 24.66
SCG	[] SCANA CORP	DEC	2.85	2.95	2.74	2.63	2.81	27.71	25.81	25.30	24.32	23.28	38.64 - 26.01	44.06 - 27.75	45.49 - 32.93	42.43 - 36.92	43.65 - 36.56
SRE	[] SEMPRA ENERGY	DEC	4.60	4.50	4.34	4.25	3.78	34.41	30.54	31.27	28.02	23.97 J	57.18 - 36.43	63.00 - 34.29	66.38 - 50.95	57.35 - 42.90	47.86 - 35.53
TE	[] TECO ENERGY INC	DEC	1.00	0.77	1.91	1.18	1.02	9.47	9.15	9.28	7.97	7.36	16.71 - 8.41	21.99 - 10.50	18.58 - 14.84	17.73 - 14.40	19.30 - 14.87
VVC	† VECTREN CORP	DEC	1.65	1.65	1.89	1.44	1.81	14.24	13.72	13.05	12.30	12.32	26.90 - 18.08	32.20 - 19.48	30.50 - 24.85	29.25 - 25.24	29.46 - 25.00
WEC	[] WISCONSIN ENERGY CORP	DEC	3.23	3.06	2.88	2.67	2.59	26.73	24.76	22.72	20.92	19.13	50.62 - 36.31	49.61 - 34.89	50.48 - 41.06	48.70 - 38.16	40.83 - 33.35
XEL	[] XCEL ENERGY INC	DEC	1.49	1.47	1.38	1.39	1.23	15.92 J	15.35 J	14.70 J	14.28 J	13.37 J	21.94 - 16.01	22.90 - 15.32	25.03 - 19.59	23.63 - 17.80	20.19 - 16.50
INDEPENDENT POWER PRODUCERS & ENERGY TRADE‡																	
AES	[] AES CORP	DEC	1.09	1.82	0.74	0.21	0.96	4.29	2.64	1.91	1.93	(0.17)	15.44 - 4.80	22.48 - 5.80	24.24 - 16.69	23.85 - 15.63	18.13 - 12.53
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	22.29	(7.34)	4.56	4.17	3.42	43.15	15.95	28.46	24.66	26.74	36.55 - 15.05	107.97 - 13.00	104.29 - 68.78	70.20 - 50.55	62.60 - 43.01
DYN	† DYNEGY INC	DEC	(6.25)	1.00	0.75	(4.00)	(10.65)	20.99	21.61	21.25	19.27	21.83	14.00 - 5.00	49.60 - 7.50	54.75 - 32.35	36.60 - 22.50	28.50 - 16.05
NRG	[] NRG ENERGY INC	DEC	3.70	4.09	2.14	1.95	0.34	15.91	15.89	8.19	7.84	9.71	29.26 - 15.19	45.78 - 14.39	47.19 - 27.22	29.74 - 20.90	24.72 - 15.15
OTHER COMPANIES WITH SIGNIFICANT NATURAL GAS OPERATIONS																	
TRP	TRANSCANADA CORP	DEC	2.02	2.07	2.34	1.85	2.14	16.00	11.27	13.41	13.02	12.59	34.59 - 20.01	41.53 - 23.52	43.94 - 31.33	35.40 - 27.40	32.43 - 23.36

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
J-This amount includes intangibles that cannot be identified.