Q. McShane Evidence - Credit Metrics, pages 22-27

a. Ms. McShane discusses NP's credit upgrade by Moody's, regardless of the motivation would she accept that a Moody's A2 rating is one of the highest ratings awarded by Moody's to a Canadian regulated utility. Please provide the names of companies with higher ratings.

b. Would Ms. McShane accept that by securing its debt, this effectively ring fences NP and reduces its financial risk relative to that of many US companies.

c. Please indicate whether Moody's has issued any general utility risk assessment reports after the 2009 report and provide copies of both any updates and the 2009 report.

d. Please confirm that NP's credit metrics should improve as a result of the low interest environment and the rollover of higher cost debt.

A. a. NP is one of only two utilities in Canada which have senior secured debt or first mortgage bond debt rated by Moody's. Its senior secured rating is one notch below the senior secured rating of FortisBC Energy Inc. Its senior secured rating is equal to (Allete) or below (AGL, Integrys, Vectren) the ratings on any of the senior secured debt issued by the operating companies in Ms. McShane's U.S. utility sample.

b. Securing debt does provide a form of "ring fencing", as holders of secured debt have first call on the secured assets. All other things equal, holders of secured debt are exposed to lower risk than holders of unsecured debt. Ms. McShane cannot confirm that the fact that Newfoundland Power's debt is secured makes its financial risk from an equity investor's perspective less risky than that of many U.S. utilities.

c. On June 18, 2010, Moody's published two articles entitled "Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities: Evaluating a Utility's Regulatory Framework" and "Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality: Evaluating a Utility's Ability to Recover Costs and Earn Returns". As these articles are subject to copyright protection, Ms. McShane objects to placing them on the public record. Please see "CA-NP-369c Attachment 1.pdf" and "CA-NP-369c Attachment 2.pdf" for copies of the document on Newfoundland Power's stranded website at the link ftp.nfpower.nf.ca.

d. As a general proposition, yes, although the extent to which that is the case depends in part on the allowed ROE and capital structure.

"Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities: Evaluating a Utility's Regulatory Framework"

MOODY'S
INVESTORS SERVICE

SPECIAL COMMENT

Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities

Evaluating a Utility's Regulatory Framework

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Analyst Contacts:

NEW YORK 1.212.553.1653

Laura Schumacher 1.212.553.3853
Vice President-Senior Analyst
Laura.Schumacher@moodys.com

W. Larry Hess 1.212.553.3837
Team Managing Director
William.Hess@moodys.com

» Analyst contacts continued on the last page

Summary

The framework in which a regulated utility operates is typically one of its most significant credit considerations. The regulatory structure and its general framework is a primary consideration that differentiates the industry from most other corporate sectors.

The characteristics of a utility's regulatory framework represents one of four factors that are considered, within the context of Moody's Regulated Electric and Gas Utilities Rating Methodology, published August 2009, (the Rating Methodology) to determine its rating. This Special Comment discusses our scoring criteria on that first factor.

A key consideration in our analysis is the degree to which a utility's regulator has the ability to independently regulate within the context of its legal, legislative or political environment.

We also examine how developed the utility's regulatory framework is; the decision making track record of its regulators; the utility's business model; and its regulators' openness to alternative rate mechanisms that help assure timely cost recovery.

We also evaluate patterns of regulatory contentiousness, which is often driven by political intervention at some level, in an effort to develop a view toward regulatory bias. This is one of the more challenging aspects to our analysis, since political intervention often occurs quickly and unexpectedly. Ultimately, we look to evaluate how the act of balancing a utility's appropriate cost of service and return on investment with consumer's ability and willingness to pay may change over time. Today's economic turmoil appears to be having some implications for this assessment in selected jurisdictions.

In the U.S., the vast majority of utilities operate within state regulatory frameworks that are reasonably transparent and well developed where regulators generally strive for a fair balance in establishing rates that assure reliable service at a reasonable cost to ratepayers while allowing a utility a fair opportunity to earn a reasonable return. However, assessing this balance is a complex procedure, and frequently involves a subjective assessment on our part. While most utilities in the U.S. score within the Baa range on the regulatory framework factor, indicating relatively solid support from a credit perspective – there are a few notable exceptions.

In Asia, with the exception of Hong Kong, Singapore and Japan, the regulatory framework is generally less transparent, and regulators may be under political pressure to reduce or maintain rates. In Europe, utilities that fall under the subject Rating Methodology, do so either because their regulatory and market development has taken place somewhat later than other countries within the EU[1], or because they are somewhat isolated and have received an exemption to the EU Electricity Directive. In Canada, the provincial regulatory frameworks are well developed, transparent and predictable, and most utilities score in the A range on the regulatory framework factor. In Latin America, regulatory frameworks vary with some being stable and transparent while other are constantly shifting and prone to political intervention.

It is important to note that our evaluation of a utility's regulatory framework is company specific, and that the score assigned for Factor 1 considers management's ability, over time, to cultivate supportive regulatory relationships.

Introduction

When evaluating the credit quality of a utility, the degree of support that it may depend on from its regulators is typically one of Moody's most significant considerations. The regulatory framework is also the prime factor in differentiating the industry from most other corporate sectors. This is partly due to the fact that a typical utility provides services that are essential to our way of life and to our economy, namely the delivery of electricity and/or natural gas. Utilities typically do not compete with other companies for the ability to provide these services, although some highly structured pockets of competitive retail "supply" of electricity have been introduced across the U.S. As a monopoly, the activities of a utility are usually conducted within a legislatively mandated oversight framework – where the national, provincial or state regulatory commissions - can review costs associated with the need to provide consistently safe and reliable service, plus provide a reasonable profit. Consequently, a utility's total, over-all revenue requirements and the rates associated with generating those revenues, are important considerations in evaluating this factor.

As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors.

In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly. Because of the regulatory safety net, defaults are rare in this sector, as compared with most industrial companies. However, there have been seven major investor owned utility defaults in the United States over the last 50 years, five of which resulted in Chapter 11 bankruptcy filings. In five of the defaults, a dispute with regulators regarding an insufficient or delayed response to a request for financial relief associated with the recovery of costs and/or capital investment in utility plant is generally cited as a primary driver that led to growing financial pressure, credit rating downgrades and, in most cases, the eventual filing for bankruptcy.

[1] The EU Electricity Directive of 1999 ("the Directive") ushered in a period of liberalisation of generation and supply prices and hence most European vertically integrated utilities are covered under the Unregulated Utility and Power Companies Methodology

In our Regulated Electric and Gas Utilities Ratings Methodology, published August 2009, (the Rating Methodology) the importance of regulatory influence is emphasized by the 50% weighting [2] ascribed to various statutory and regulatory provisions when determining a utility's credit quality. Factor 1, Regulatory Framework, the first of four key factors, is ascribed a 25% weighting and considers the general regulatory and political environment under which a utility operates and the overall business position of a utility within that regulatory environment. Factor 2, Ability to Recover Costs and Earn Returns, is also ascribed a 25% weighting and addresses in a more specific manner the ability of an individual utility to recover its costs and earn a fair return on invested capital.

TABLE 1

Regulated Electric and Gas Utility Rating Methodology

KEY RATING FACTORS AND WEIGHTINGS
1. Regulatory Framework – 25%
2. Ability to Recover Costs and Earn Returns – 25%
3. Diversification – 10%
4. Financial Strength and Liquidity – 40%

Factors 1 and 2 are inter-related in numerous ways. For example, whereas Factor 2 evaluates a company's specific success at earning returns and generating adequate, predictable cash flows, possibly as a result of its use of recovery mechanisms, such as those for fuel and purchased power, environmental, renewable or other expenses, Factor 1 considers, among other things, the regulator's demonstrated willingness to authorize a use of enhanced recovery mechanisms and to provide an ability for the company to earn adequate returns. This Special Comment discusses how we calculate a utility's score for Factor 1 - Regulatory Framework. (The current Factor 1 scoring for the operating utilities in our rated universe is shown in Appendix A). These Factor 1 scores provide an indication of our current thinking. The scores are not intended to be static; they continue to be monitored and modified as warranted to reflect changing conditions and circumstances. In addition, when applied within the context of the Rating Methodology framework grid, the scores shown in Appendix A may be further modified by the use of a "strong" or "weak" designation.

What are the characteristics of a utility's regulatory framework?

In evaluating a utility's regulatory framework, we consider such things as the regulatory body's independence; its legislative or political environment; the extent of the regulatory framework's development; its track record for predictable, stable decisions; the utility's business model; and the openness of the regulators to alternative rate mechanisms that tend to provide additional assurance of timely cost recovery and the ability to earn a return on invested capital.

Regulatory Independence

A key consideration in assessing Factor 1 is the degree to which the regulator has the ability to act as an unbiased arbiter over the facts in the record, and base its decisions on the existing laws and statutory decisions. Today, balancing the sometimes conflicting goals of assuring a reliable supply of reasonably priced electricity or natural gas; assuring the long-term financial health of the utilities it regulates; and authorizing rate increases within a given state or region is increasingly viewed as challenging.

[2] The factor weightings shown in the rating methodology grid are approximate. The actual weight given to a factor in our assessment of an issuer's credit quality may differ based on the issuer's circumstances, and the scoring grid does not include every consideration that determines a rating.

We look to see if the regulator consistently strives to achieve balance, between the investor and the consumer in assessing the utility's rate request, or substantially denies the rate request by acting perhaps in a manner more akin to a consumer advocate.

We also evaluate the impact of outside political influence on the regulatory process, where a legislature or a governor can revise, amend or restructure certain provisions associated with the traditional, vertically integrated electric utility framework. Political influence works in many ways, from utility sponsored legislation on the positive side to wholesale reductions to recovery on the negative side.

The majority of utilities in the rated universe of the Rating Methodology are considered to have average exposure to regulator independence, meaning their regulators generally try to take the middle path. There are a few notable exceptions, for example, in Indonesia, or in Argentina where the politicization of the regulatory relationship tends to be a dominant factor in assigning a score to the regulatory framework factor.

National and local regulation

When a utility's revenues are determined by a single national regulator, within a well developed and transparent framework, Moody's generally views the framework as being more independent, less susceptible to local political influence and more supportive of long-term utility credit quality than state regulation. The difference in risk reflects our view that national regulation tends to be more transparent and sometimes even formulaic, and less exposed to significant political or consumer intervention. This tendency is best exemplified in markets that are large, well developed, and relatively transparent; such as the U.K or Japan.

In smaller markets, national regulators may also be susceptible to local pressure, In Asia, each country has one regulator, but with the exception of Hong Kong, Singapore and Japan, the regulatory framework is generally less transparent, and in some countries, the regulators are under political pressure to maintain or reduce rates.[3] The economic recession of the past few years has also put pressure on national regulators in Central and Eastern Europe as well.

In Latin America, the regulatory frameworks vary from one country to another, in some countries, such as Chile, utility regulatory frameworks have been in place for an extended period, and are quite transparent; for others, such as in Argentina, the frameworks are constantly shifting and subject to political influence, while in Brazil the frameworks are more developed but still evolving. Federally regulated utilities in Argentina, which serve the most densely populated areas of the country, tend to be more subject to public scrutiny than the local, smaller utilities in the interior of the country. As a result, regionally regulated utilities have been favored by rate increases more often and in a more timely manner than federally regulated utilities.

In Canada, the provincial regulatory frameworks are well developed, transparent and predictable. In addition, Canadian utilities generally have not pursued diversification strategies and have limited exposure to unregulated activities at affiliates or holding companies. We view Canada's business and regulatory environments as being more supportive than many of those in the U.S. Accordingly, most utilities in Canada score in the A range on the regulatory framework factor.

[3] For example, there has been limited tariff increases in Indonesia for the past few years and Malaysia kept its rates unchanged from 1999 to 2006.

We would be likely to assign a score of Aaa or Aa for a utility's regulatory framework factor in jurisdictions where regulators are likely to take extraordinary action to support a failing company,[4] or where a utility can set rates independently, like the U.S. owned Tennessee Valley Authority. Additionally, U.S.-based transmission companies, which enjoy formulaic federally regulated rates determined by the Federal Energy Regulatory Commission (FERC), but do not see extraordinary supportive action from their regulator, are currently scored in the Aa range because of the transparent and predictable characteristics of that framework.

U.S. Transmission Regulation

In an effort to encourage investment in the aging U.S. transmission infrastructure, the FERC established a transparent and supportive approach to establishing rates for significant transmission projects. Elements of this approach include:

» Authorized returns on invested capital that are generally higher than those awarded by state regulators;

» An ability to earn a cash return on construction work in progress;

» An ability to recover abandonment costs;

» A significant equity component is allowed in capital structures and companies have the ability to utilize double-leverage;

» No rate hearings required to adjust rates;

» Rates reset annually via established formula, assuring timely recovery of actual costs and return on investment;

» The rate formula may be forward looking.

In our opinion, state-regulated investor-owned U.S. utilities carry higher regulatory risk than utilities with rates regulated entirely by FERC. The U.S. market is highly fragmented: many utilities are exposed to overlapping or unclear regulatory jurisdictions, and to volatile power prices. And since state regulation is far more local, it can become political - particularly when significant rate increases are proposed. Currently, all state regulated U.S. investor-owned utilities receive scores that range from "A" to "Ba" for the regulatory framework factor.

We also acknowledge that a utility's operations are subject to regulation on numerous fronts, including operational safety and environmental controls. In these cases, federally or nationally imposed regulation, that does not consider local conditions, may create additional uncertainty or may result in a disproportionate impact for individual utilities.

Political tendencies

When a utility's rate setting process is exposed to significant political interference, its rate-case outcomes become less predictable, often resulting in reduced expectations for cash flow stability, and in many instances introducing a long-term period of contentiousness. Utilities with a history of politically charged rate proceedings will tend to score in the ranges of either Ba or B on the regulatory framework factor. We have observed that while utilities may ultimately prevail through legal

[4] This tends to be the case for utilities in Japan.

challenges, the process can take years to complete, and in most cases, the damage to credit quality will have already occurred.

In evaluating the potential for political interference in the U.S., we look beyond the method of commissioner selection (elected versus appointed). In our view, all regulation is political, so we do not differentiate in a significant manner how the commissioners got on the commission. In states where voters elect their regulatory commissioners, it might seem that consumer oriented political intervention - or a bias toward appearing to do everything possible to minimize rate increases, would be a heavy factor in rate case outcomes. In fact, while this is often the case, we have not found it to consistently be true.

Utilities in Arizona and New Mexico, where commissions are elected, have tended to experience protracted and highly publicized rate proceedings; as a result, utilities in these jurisdictions currently receive regulatory framework scores in the Ba range. Yet in numerous states with elected commissions such as Alabama, Georgia, North Dakota and South Dakota, utilities have not had a history of lengthy or politically charged rate proceedings. Many utilities in these states receive regulatory framework scores in the A range. It should be noted that a utility often represents one of the largest publicly-traded companies headquartered within a particular state that also employs a significant amount of the population with reasonably good jobs, is usually ascribed a substantial property tax bill and is often a very generous contributor to local charities.

On the other hand, the most significant recent examples of negative political intervention that posed a severe threat to utility credit has occurred within regulatory jurisdictions where commissioners were appointed, but their ability to act independently was impaired by the actions of politicians. We have seen this happen in recent years for utilities operating in Illinois and Maryland, which are now scored Ba on regulatory framework, but scored in the B range or lower amid threats of continued rate freezes or caps.

Utilities in California, which also has an appointed commission, faced extreme political opposition during the energy crisis of 2001-2002. Some of these utilities ultimately defaulted. This history is a key consideration in the score assigned to the regulatory framework for these companies; although for the past several years, the regulatory treatment for utilities in California has been among the more credit supportive observed for U.S. utilities, and until recently, their scores on Factor 1- Regulatory Framework remained within the Baa range. Currently, they are scored in the A category. In Florida, where the commission is appointed, utilities have historically experienced very supportive rate decisions, and those utilities had historically received scores in the A range. However, recent interventions by the Governor in the rate proceedings for Florida Power & Light and Progress Energy Florida - including the appointment of new commissioners in the midst of rate proceedings have contributed to our reassessment of this rating factor for these companies, resulting in lower regulatory framework scores for Factor 1 in the Baa range.

Outside of the U.S., utilities in Argentina provide a clear example of regulatory environments that are currently subject to a significant amount of political interference. Initially, ENARGAS was established as an independent agency to administer and enforce the Gas Act and applicable regulations for the gas distribution industry, including the tariff setting and periodic tariff review mechanisms. However, following the 2001-02 crisis, on July 2003 the Argentine government created a new agency (UNIREN or Agency to Renegotiate Public Utilities Contracts) to develop a common regulatory framework for all utilities and to renegotiate their tariffs. In addition, since May 2007 ENARGAS has been under an intervention decreed by the President, who appointed an official (or "Interventor") to be in charge of the agency. Therefore, many of the ENARGAS' technical duties are subject to political interference and as a consequence the regulatory framework is not transparent and highly unpredictable. As an example, Metrogas, an Argentine regulated LDC, has not been able to adjust its tariffs in over ten years, which has lead to a severe deterioration of the company's economic and financial situation. On June 17, 2010, the company filed for reorganization under Argentine law.

In some instances, political or legislative actions can, in fact, be supportive of utility credit quality – putting forth additional rate mechanisms or tools for state commissions to consider, or legislating specific time frames for rate decisions. Such actions generally offer the opportunity for a utility to receive more supportive treatment from its regulators, but they generally also require regulatory follow-through; and are typically not intended to impede the regulator's ability to balance the utility's need to recover its costs and earn a return with the desire to maintain reasonable rates. As a result, credit supportive legislative actions are generally less likely to immediately affect a utility's Regulatory Framework score.

Some political interventions have hurt utilities' credit quality

- When Illinois was preparing to fully transition to electric market rates for generation in 2006 and 2007, several bills were proposed that would re-freeze the electric rates for the state's primary utilities that had just come off a 10-year rate freeze. The bill's legislative progress caused considerable rate uncertainty – particularly since the regulator, the Illinois Commerce Commission, had already sanctioned power supply auctions for power procurement and approved rate phase-in plans. We considered the significant potential impact on utility cash flow as a major threat to credit quality which ultimately resulted in ratings downgrades to below investment grade for each of the Illinois transmission and distribution companies.

  An August 2007 settlement avoided a more severe negative impact on the utilities' rates and credit ratings, and more recent regulatory proceedings have been concluded without direct political interference. However, this experience suggests the future possibility of political or consumer backlash if significant rate increases become necessary again . Moreover, the utilities' continued relationship with unregulated generation affiliates remains unchanged which was a primary motivation, in Moody's opinion, for the political pushback to transitioning to market rates for generation.

- Maryland also experienced a significantly politicized regulatory environment in 2006-2008 as its move towards electric retail competition became a major legislative and gubernatorial issue and was exacerbated by a potential acquisition of Constellation's Baltimore Gas & Electric Company (BG&E) utility subsidiary by Florida based FPL Group. New legislation produced significant uncertainty regarding electric utilities' ability to recover their increased costs for fuel and purchased power which ultimately resulted in significant deferrals and required refunds. Importantly, this legislation was passed after the Maryland Public Service Commission (MPSC) had already approved a plan that provided a more moderate deferral of rate increases. The legislature also voted to replace the full slate of MPSC commissioners - a highly unusual event.

  During this time, the ratings of BG&E were downgraded by a total of three notches and remain at that level today. A spring 2008 settlement led to legislation that essentially resolved all issues; but not without a significant sustained reduction in BG&E's expected cash flow credit metrics. This relatively recent past experience, leads us to believe future political intervention cannot be entirely ruled out.

… while others have been supportive

- In Georgia, South Carolina and Florida, legislation has been enacted that permits utilities to earn a cash return on construction work in progress on nuclear plants. Moody's views this type of legislation positively as the resulting mechanisms provide support for a utility cash flows and credit metrics while significant construction is underway, and they also tend to reduce the potential for future rate shock.
- Michigan passed legislation in 2008 designed to reduce rate lag and encourage utility investment. In its 2009 and 2010 implementation of the legislation, the Michigan Public Service Commission appeared, in our opinion, to apply the legislation as intended; however, they also appeared to carefully balance the utilities' cost recovery needs with a need to minimize rate increases in a struggling economy. Such legislation has been a primary factor in the financial performance of the state's investor-owned utilities, given the severe economic contraction throughout the state.

Level of Development of the Regulatory Framework

Utilities that are operating within regulatory frameworks that are not well defined, or are relatively new, such as Eskom Holdings in South Africa, Israel Electric Corporation in Israel, Empresa Electrica de Guatemala S.A in Guatemala, and PLN in Indonesia will tend to receive lower regulatory framework scores, since a lack of development and track record reduces the level of predictability of rating outcomes and cash flow.

In Argentina, although a reasonable regulatory framework was established during the 1990's, and worked relatively well for almost 10 years, it was followed by a period of constant change of rules with very little support for the utilities' cost recovery requirements. In fact, for the past ten years, the majority of companies have been operating with frozen tariffs while costs continue to escalate. As a result of this high level of regulatory uncertainty and political intervention in the rate setting mechanism, the regulatory framework score for Factor 1 for all utilities in Argentina is in the B range.

Utilities in Brazil operate under a regulatory model that is well developed but with a relatively limited track record. The framework was implemented in 2004, and has generally evolved in a manner that has been supportive of utility investment and credit quality. Structural enhancements have included more efficient methods of power procurement, expansion of the national grid, centralization of long term energy planning, and increased thermoelectric capacity. Recognizing these improvements, in 2008 the regulatory framework score improved to Ba from B. However, the federal regulator is not fully independent of political pressure, and currently there is a fair amount of uncertainty surrounding the potential renewal or revocation of some utility concessions. As a result, the Factor 1 score for utilities in Brazil remains in the Ba range.

In certain instances, a utility's regulatory framework score could be tempered by the uncertain effects of policy changes (such as a transition to competition), or the implementation of new laws. As discussed above, Michigan in 2008 passed legislation enabling the Public Service Commission to give above-average support to its utilities - something which has proven to be beneficial in the current economic downturn. Even so, the improved regulatory environment is still relatively new and our concern about the sustainability of utility support in a continued weak economy holds Michigan utilities' regulatory framework scores in the Baa range.

Turnover among state regulatory commissioners may also increase the uncertainty surrounding rate case decisions. New commissioners often face challenges in quickly coming up to speed on complicated rate issues and obviously lack an established track record. Turnover that results from political intervention in opposition to rate increases, as we recently saw in Florida, is highly likely to have a negative impact on a utility's regulatory framework score.

Considerations within European Markets

The European utilities that fall under the Regulated Electric and Gas Utilities Rating Methodology, do so either because their regulatory and market development has taken place somewhat later than other countries within the EU or where they exist within isolated regimes where significant competition would be hard to achieve (such as the Portuguese regions of Azores and Madeira)[5] and hence have received an exemption to the Directive.

The regulatory frameworks that have been implemented in Central and East European (CEE) countries tend on the one hand to have benefited in the first place from the adaptation, albeit with some modifications, of the already well-established UK regulatory framework. However as the CEE utility markets have been historically rather fragmented, with varying speeds of liberalisation, the full application of a well defined, transparent and consistent regulatory mechanism does vary from region to region. The common factor affecting our evaluation of regulatory regimes in CEE is their short track record compared to the more established regulatory regimes in Western Europe.

In addition, the economic recession of the past two years, revealed a greater-than-expected political influence over the decisions of regulatory bodies even in the more developed CEE countries such as Poland or Slovakia. The adverse economic impacts of the recession raised the political pressures on regulatory regimes not only in the regions with historically highly politically-influenced regulation such as in South East Europe, but also resulted in increasingly politically and socially motivated decisions of historically more consistent and transparent regulatory regimes in Central Europe. Whilst certain regulatory decisions, such as the price cap established by the Slovak regulatory office across most of the regulated sectors or the reluctance of the Polish regulator to adjust tariffs during gas price hikes, have to be seen in the context of the extreme commodity price volatility recorded over the 2008-09 period, it appears that the independence of CEE regulatory regimes from political influence is still fragile and together with short track records prevents a high score on Factor 1.

Predictability and Stability

Utilities accustomed to fairly stable and predictable rate-proceeding outcomes tend to receive higher regulatory framework scores. This is heavily linked to the degree of a regulator's independence and how developed its framework is, but for utilities whose scores are not dominated by these factors, regulatory treatment over time may be a differentiating factor.

Regulation affects utility credit quality most directly by establishing prices (rates) for the electricity, gas and related services that the utility provides (revenue requirements), and by determining the authorized return on a utility's investment, as well as the authorized return to shareholders. In evaluating a utility's regulatory framework, we consider whether it has consistently been given rate increases that provides it an opportunity to recover its expenses and actually earn a rate of return in line with shareholder expectations.

Requested and authorized rates of return (ROEs) have trended downward over the last two decades, from about 12-13% in the early 1990s to the 10%-10.5% range more recently. Much of the decrease has stemmed from falling interest rates, but some of the decline may be attributed to other mechanisms put in place to ensure timely recovery and reduce risk (see next section). In evaluating the

[5] In this instance, they are subject to well-established Portuguese regulation under Entidade Reguladora dos Serviços Energéticos, where we apply a Baa to the Regulatory Framework

predictability of cash flows, we are concerned less with the awarded ROE, which has a tendency to become a headline, than the overall collective rate outcome, including the authorized base rate increase, the impact of any approved enhanced recovery mechanisms such as riders or trackers, and the implications for future cash flows. We observe that the amount of regulatory lag can be a contributing factor to a utility not being able to earn their authorized rate of return. From a credit perspective, while we are also less concerned with shareholder returns, we do observe that those companies that earn at or near their authorized rate of return tend to produce more predictable cash flows; and those companies that are not able to earn their authorized return tend to produce relatively weaker cash flow credit metrics.

The past two years have seen a tremendous amount of electric rate case activity, with rate increases generally coming in at slightly more than 50% of the requested amount. In prior years, when there was less activity, awards tended to be closer to 40%. Gas rate case awards, which have tended to be less politically contentious, have come in more consistently around 50%. While history tells us it is unlikely a utility would be awarded the full amount of its requested increase, companies that manage their regulatory relationships in a way that allows them to consistently achieve awards that provide an opportunity to earn a fair rate of return, would be more likely to receive an above average regulatory framework factor score.

Utilities that have received unwelcome surprises from regulators, with awards significantly lower than anticipated or less than enough to generally maintain or improve credit metrics, are likely to have a lower regulatory framework score. For example, the outlook of Consolidated Edison Company of New York (CECONY) was revised to negative and its ratings were ultimately downgraded following a change in our view of CECONY's historical relationship with its regulator and the extent to which we could expect future rate actions to be supportive of credit quality. In 2008, CECONY received a rate increase that was only about 35% of its requested amount, premised on a 9.1% ROE, which was significantly below the average ROE of 10% or so that was then typical for transmission and distribution utilities in other regulatory environments.

Alternative Rate Making Mechanisms

Another key aspect of a utility's regulatory framework is the regulator's openness to policies that could ease rate lag. Such policies could include the tendency for its rate cases to be settled rather than litigated over a protracted period, the use of interim rates and/or forward test years.

Other mechanisms are designed to assure cost recovery and give utilities the chance to earn allowed rates of return. These include such things as, pre-approval of recovery of investments for new generation, transmission or distribution; the inclusion of construction work in progress (CWIP) in utility rate bases; the existence of attrition revenues which provide cash returns on construction expenditures, the inclusion of riders or trackers for specific investments or expenses; and the design and administration of mechanisms that allow the recovery of prudently incurred costs for fuel and purchased power.

Where rate design reduces or eliminates the utility's exposure to fluctuations in gas or electricity consumption that can be caused by weather, economic conditions, gas or power costs or legislative or regulatory conservation requirements, the utility is likely to enjoy more stable revenue and cash flow than would otherwise be the case. This form of rate design, known as decoupling, tends to lower a utility's business risk and could contribute to higher scoring on Factor 1.

Although the impact of these factors on any given utility is considered more specifically when assigning scores to the second of the four factors utilized to determine utility credit quality, the ability to recover costs and earn returns, and as described more fully in Moody's Special Comment on Cost Recovery Provisions dated June 2010, to the extent these mechanisms have been a consistent part of the regulatory framework for some time it would also be considered positively when assigning a score to the regulatory framework factor.

A Utility's Business Model Could Affect Regulatory Framework Score

In evaluating the regulatory framework we also consider a utility's business model and its impact on its relationship with its regulators. We consider the amount and type of unregulated activity that a company may be engaged in as well as the nature of its regulated operations.

For utilities with some unregulated operations, we will look at the competitive and business position of these unregulated operations. 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 utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be the case if the utility had solely regulated operations.

We also consider the degree to which a utility might be indirectly exposed to unregulated business risks by virtue of the ownership of such businesses by affiliates or parent holding companies. We will consider the tendency of parent companies to pursue diversification strategies which, in the absence of effective ring-fencing mechanisms, could expose the regulated utility to increased financial risk. Historically, holding company diversification into unregulated, and sometimes unrelated, business lines and into international markets has had generally negative credit consequences for regulated utility subsidiaries.

We also evaluate the nature of the utility's regulated businesses. Local Gas Distribution Companies sometimes referred to as LDCs, are generally considered to have lower business risk than electric utilities. These utilities tend to almost universally have mechanisms in place that pass the commodity cost of gas directly to their customers, tend to have capital expenditure plans that are more consistent than electric utilities, reducing the need for large sudden rate increases; and tend to have less contentious issues with their regulators. Decoupling, a concept designed to protect a utility from the risk of declining usage, has become more prevalent in recent years as regulators have sought to encourage energy efficiency, and is currently much more prevalent in gas utilities. Therefore, LDCs could receive higher scores on the regulatory framework factor than electric utilities operating within the same jurisdiction.

In jurisdictions that have deregulated power generation activities, utilities have been left with only a delivery obligation, giving them - in theory - a lower business risk profile as they are not exposed to the costs and operating risks associated with power production. However, in many deregulated markets, the utility maintains a provider of last resort (POLR) obligation, and may be subject to rate caps or freezes that do not always allow the full timely recovery of costs for power purchased or hedged to meet their POLR obligations. A utility that provides only transmission and distribution services, and truly has no exposure to retail customers, is viewed as having a lower business risk profile and its regulatory framework would likely score above average. This is true for the majority of the transmission and distribution utilities operating in Texas, the Factor 1 scores for these companies are in the A range. Conversely, utilities with significant POLR and under-recovery risk tend to score below average.

Vertically integrated electric utilities are generally considered to have higher business risk than T&D utilities due to the risks associated with generation including fuel price and volume, operational and environmental risks. Among utilities with generation, those with significant exposure to fossil fuels, particularly coal, are typically viewed as having higher risk due to uncertainty as to the timing and amount of capital expenditures required to comply with further anticipated restrictions on environmental emissions including carbon dioxide, mercury, sulfur dioxide and nitrogen oxides.

Regulatory Framework Score is Utility Specific

It is important to note that our evaluation of a utility's regulatory framework is company specific, considering each company's experience and track record at cultivating supportive regulatory relationships and operating within its framework. Although utilities operating within the same framework will tend to have similar Factor 1 scores, it is possible to have deviations based on actual experience. For example:

In Florida, a historically supportive environment, Progress Energy Florida, Inc. and Florida Power & Light's recent sizeable rate increase requests, which were proposed against a backdrop of a significantly weakened economy, resulted in an unprecedented (for Florida) amount of political intervention, and rate increases that were severely limited, or denied. As a result, we have lowered the Factor 1 score for these companies to Baa from A. This does not necessarily mean that we would automatically lower the regulatory framework scores for all utilities in Florida to the same degree. Gulf Power Company, for example, which has not filed for a base rate increase in several years and is not expected to do so over the near term, is insulated to some extent from the current, perhaps temporarily deteriorated, political and regulatory environment in the state.

In Virginia, a regulatory environment also historically viewed as supportive, legislation passed in 2007 essentially to re-regulate the electric industry has impacted utilities differently. Virginia Electric and Power Company (VEPCO), in March received commission approval of a unanimous settlement agreement, which included a base rate ROE of 11.9%. The settlement resulted in no change in VEPCO's base rates (but did require significant refunds and rate credits); however, it also allows VEPCO to adjust rates via rider mechanisms for various transmission, generation and efficiency investments. As a result, cash flows are expected to remain adequate and VEPCO's Factor 1 score is currently A. On the other hand, in 2008 the commission rejected Appalachian Power Company's (APCO) proposed construction of an integrated gas combined cycle plant, and associated request for a premium ROE. In APCO's pending rate case, staff is recommending an increase of approximately $40 million, while a new state law resulted in the suspension of a $154 million interim increase put in place in December. APCO also has operations in West Virginia and its score on Factor 1 is currently Baa. Allegheny Energy Inc.'s Potomac Edison Company (PEC) had substantial difficulty recovering its increased costs for fuel and purchase power post a June 2007 expiration of a fixed rate contract with its affiliate. Recovery was not authorized until 2008, and was implemented, subject to caps, in July 2009. On June 1st, PEC completed of the sale of its Virginia operations to two electric cooperatives.

A utility's treatment within its regulatory framework, and our assessment of its Factor 1 score, often may have less to do with the regulator and much to do with the company and their cultivation of the regulatory relationship. It is entirely possible for a company to improve upon its regulatory relationships via open communication and negotiation toward the shared goals of providing reliable service at a reasonable cost. For example, regulatory relationships within PacifiCorp's numerous jurisdictions have generally all improved since its 2006 acquisition by MidAmerican Energy Holdings, Inc. as the company focused on understanding the needs and concerns of the regulators and other constituents within each state that it operates.

Other Considerations

On a company-specific basis, we would also evaluate factors such as the regulator's ability to oversee and ultimately approve utility mergers and acquisitions or their ability to encourage or require investments in renewable resources or energy efficiency. Environmental regulations, such as carbon capture or renewable portfolio standards could affect the regulatory framework score, particularly if they are especially onerous, for example in the U.S. southeast where renewable resources are limited. Nevertheless, these mandates are complex, usually have voluntary alternatives or offset provisions and can simply be re-legislated in the future which typically does not make these requirements a material credit issue at this time.

We also look at the substance of any regulatory or legal ring fencing provisions, including restrictions on dividends, capital expenditures and investments; separate financing provisions and/or legal structures; and limits on the ability of the regulated entity's ability to support its parent in times of financial distress. At any given time, depending on the circumstances facing the company, these may become contributing factors in determining the Factor 1 score.

Conclusion

A utility's regulatory framework is a key consideration in determining its credit quality - accounting for a significant 25% weighting - when we evaluate a utility's credit rating within the framework of our Rating Methodology.

When evaluating a utility's regulatory framework we consider such things as the independence of the regulatory body; the legislative or political environment; how developed the regulatory framework is; the regulator's track record for predictability and stability in terms of decision making; the business model of the utility; and the regulator's openness to consider alternative rate mechanisms.

Most of the utilities we rate operate in environments where regulators strive for a fair balance between assuring reliable customer service at a reasonable cost, while allowing a utility to earn a reasonable return. These companies generally score around the mid-Baa range.

Meanwhile, unusual regulatory conditions can affect a utility's credit rating for better or worse. Utilities operating in regulatory environments with a history of independent decision making and generally supportive regulatory actions receive the highest regulatory framework scores; generally within the A to Aa ranges – while those operating in environments prone to political pressure receive the lowest scores, generally within the B to Ba ranges.

Appendix A: Current Factor 1 scoring for the operating utilities in Moody's rated universe

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
Chubu Electric Power Company, Incorp.	CLP Power Hong Kong Limited	Alabama Power Company	Appalachian Power Company	Arizona Public Service Company	National Power Corporation
Chugoku Electric Power Company, Incorp.		ALLETE, Inc.	Avista Corp.	Cemig Geraçao e Transmissao	Power Sector Asset & Liabilities Management
Hokkaido Electric Power Company, Incorp.		Duke Energy Carolinas, LLC	Black Hills Power, Inc.	Companhia Energetica de Minas Gerais	Perusahaan Listrik Negara (P.T.)
Hokuriku Electric Power Company		FortisBC Inc	Central Vermont Public Service Corp.	Companhia Paranaense de Energia	
Kansai Electric Power Company, Incorp.		Georgia Power Company	Cleco Power LLC	EDP – Energias do Brasil	
Kyushu Electric Power Company, Incorp.		Hydro-Quebec	Columbus Southern Power Company	Empire District Electric Company (The)	
Okinawa Electric Power Company, Incorp.		Interstate Power & Light Company	Consumers Energy Company	Empresas Publicas de Medelin E.S.P.	
Tokyo Electric Power Company, Incorp.		Madison Gas and Electric Company	Dayton Power & Light Company	Eskom Holdings Ltd	
Tennessee Valley Authority		MidAmerican Energy Company	Detroit Edison Company (The)	Furnas Centrais Eletricas S.A	
		Mississippi Power Company	Duke Energy Indiana, Inc.	Israel Electric Corporation Limited (The)	
		Northern States Power Company (Minnesota)	Duke Energy Kentucky, Inc.	Kansas City Power & Light Company	
		Northern States Power Company (Wisconsin)	Duke Energy Ohio, Inc.	Light S.A.	
		Otter Tail Power Company	Eesti Energia AS	Monongahela Power Company	
		Progress Energy Carolinas, Inc.	EDA - Electricidade dos Acores, S.A.	NTPC Limited	
		South Carolina Electric & Gas Company	El Paso Electric Company	Public Service Company of New Mexico	
		Southern California Edison Company	Empresa de Electricidade da Madeira, S.A.	Tata Power Company Limited (The)	
		Pacific Gas & Electric Company	Entergy Arkansas, Inc.	Tucson Electric Power Company	
		San Diego Gas & Electric Company	Entergy Gulf States Louisiana, LLC	Union Electric Company	
		Virginia Electric and Power Company	Entergy Louisiana, LLC	UNS Electric	
		Wisconsin Electric Power Company	Entergy Mississippi, Inc.		
		Wisconsin Power and Light Company	Entergy New Orleans, Inc.		
		Wisconsin Public Service Corporation	Entergy Texas, Inc.		
			Florida Power & Light Company		
			Green Mountain Power Corporation		
			Gulf Power Company		
			Hawaiian Electric Company, Inc.		
			Idaho Power Company		
			Indiana Michigan Power Company		
			Indianapolis Power & Light Company		

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
			Kentucky Power Company		
			Kentucky Utilities Co.		
			Korea Electric Power Corporation		
			Korea East-West Power Co. Ltd		
			Korea Hydro and Nuclear Power Co. Ltd		
			Korea Midland Power Co. Ltd		
			Korea South-East Power Co. Ltd		
			Korea Southern Power Co. Ltd		
			Korea Western Power Co. Ltd		
			Latvenergo AS		
			Louisville Gas & Electric Company		
			Nevada Power Company		
			Northern Indiana Public Service Company		
			NorthWestern Corporation		
			Ohio Power Company		
			Oklahoma Gas & Electric Company		
			PacifiCorp		
			Portland General Electric Company		
			Progress Energy Florida, Inc.		
			Public Service Company of Colorado		
			Public Service Company of New Hampshire		
			Public Service Company of Oklahoma		
			Puget Sound Energy, Inc.		
			San Diego Gas & Electric Company		
			Sierra Pacific Power Company		
			Southern Indiana Gas & Electric Company		
			Southwestern Electric Power Company		
			Southwestern Public Service Company		
			Tampa Electric Company		
			Tenaga Nasional Berhad		

T& D Utilities

Aa	A	Baa	Ba	B
Hong Kong and China Gas Co. Ltd	AEP Texas Central Company	Atlantic City Electric Company	AES Eletropaulo	Empresa Distribuidora Norte S.A.
Oman Power and Water Procur. Co.	AEP Texas North Company	Central Hudson Gas & Electric Corporation	AES El Salvado Trust	Empresa Jujena de Energia S.A.
	CenterPoint Energy Houston Electric, LLC	Central Maine Power Company	Baltimore Gas and Electric Company	
	FortisAlberta Inc.	Cleveland Electric Illuminating Company (The)	Bandeirante Energia S.A.	
	Hydro One Inc.	Connecticut Light and Power Company	Cemig Distribuição S.A.	
	Newfoundland Power Inc.	Consolidated Edison Company of New York	Centrais Eletricas do Para S.A.	
	Oncor Electric Delivery Company	Jersey Central Power & Light Company	Centrais Eletricas Matogrossenses S.A.	
	Superior Water, Light and Power Company	Massachusetts Electric Company	Central Illinois Light Company	
	Texas-New Mexico Power Company	Metropolitan Edison Company	Central Illinois Public Service Company	
		Narragansett Electric Company	Commonwealth Edison Company	
		New England Power Company	Comp. de Ener. Eletr. do Est. do Tocantins	
		New York State Electric and Gas Corporation	Delmarva Power & Light Company	
		Niagara Mohawk Power Corporation	Duquesne Light Company	
		NSTAR Electric Company	Empresa Electrica de Guatemala, S.A.	
		Ohio Edison Company	Energisa Paraíba-Dist. de Energia S.A.	
		Orange and Rockland Utilities, Inc.	Energisa Sergipe - Dist. de Energia S.A.	
		PECO Energy Company	Escelsa	
		Pennsylvania Electric Company	GAIL (India) Ltd	
		Pennsylvania Power Company	Illinois Power Company	
		PPL Electric Utilities Corporation	Light Serviços	
		Public Service Electric and Gas Company	Perusahaan Gas Negara	
		Rochester Gas & Electric Corporation	Potomac Edison Company (The)	
		Toledo Edison Company	Potomac Electric Power Company	
		United Illuminating Company	Rede Energia	
		West Penn Power Company	Rio Grande Energia S.A. - RGE	
		Western Massachusetts Electric Company	Towngas China Co. Ltd	
			Xinao Gas Holdings Ltd	

Transmission Only Utilities
Aa
American Transmission Company LLC
American Transmission Systems
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company
Trans-Allegheny Interstate Line Company

Local Gas Distribution Companies (LDCs)

Aa	A	Baa	Ba	B
Terasen Gas Inc.	Atlanta Gas Light Company	Bay State Gas Company	Cia de Gas de Sao Paulo - COMGAS	Camuzzi Gas Pampeana S.A.
	Piedmont Natural Gas Company, Inc.	Berkshire Gas Company	Source Gas LLC	Gas Natural Ban S.A.
	Public Service Co. of North Carolina, Inc.	Boston Gas Company	UNS Gas	Metrogas S.A.
	Southern California Gas Company	Brooklyn Union Gas Company		
	Terasen Gas (Vancouver Island) Inc.	Cascade Natural Gas Corp.		
	Wisconsin Gas LLC	Colonial Gas Company		
		Connecticut Natural Gas Corporation		
		Indiana Gas Company, Inc.		
		Laclede Gas Company		
		Michigan Consolidated Gas Company		
		New Jersey Natural Gas Company		
		North Shore Gas Company		
		Northern Illinois Gas Company		
		Northwest Natural Gas Company		
		Peoples Gas Light and Coke Company		
		SEMCO Energy, Inc.		
		South Jersey Gas Company		
		Southern Connecticut Gas Company		
		Southwest Gas Corporation		
		UGI Utilities, Inc.		
		Washington Gas Light Company		
		Yankee Gas Services Company		

Moody's Related Research

Rating Methodologies:

» Regulated Electric and Gas Utilities, August 2009 (118481)

» Unregulated Utilities and Power Companies, August 2009 (118508)

Industry Outlooks:

» U.S. Electric Utilities Face Challenges Beyond Near-Term, January 2010 (121717)

Special Comments:

» Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality, June 2010 (122304)

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.

» contacts continued from page 1

Analyst Contacts:

NEW YORK	1.212.553.1653
James Hempstead *Senior Vice President* James.Hempstead@moodys.com	1.212.553.4318
A.J. Sabatelle *Senior Vice President* Angelo.Sabatelle@moodys.com	1.212.553.4136
Michael G. Haggarty *Senior Vice President* Michael.Haggarty@moodys.com	1.212.553.7172
Mihoko Manabe *Vice President-Senior Credit Officer* Mihoko.Manabe@moodys.com	1.212.553.1942
Kevin G. Rose *Vice President-Senior Analyst* Kevin.Rose@moodys.com	1.212.553.0389
Scott Solomon *Vice President-Senior Analyst* Scott.Solomon@moodys.com	1.212.553.4358
James O'Shaughnessy *Analyst* James.Oshaughnessy@moodys.com	1.212.553.1607
Natividad Martel *Analyst* Natividad.Martel@moodys.com	1.212.553.4561

TORONTO	1.416.214.1635
Allan McLean *Vice President-Senior Credit Officer* Allan.McLean@moodys.com	1.416.214.3852

HONG KONG	1.852.3551.3077
Jennifer Wong *Assistant Vice President–Analyst* Jennifer.Wong@moodys.com	1.852.3758.1373

SAO PAULO	5511.3043.7300
Jose Soares *Vice President-Senior Analyst* Jose.Soares@moodys.com	5511.3043.7339

BUENOS AIRES	5411.4816.2332
Daniela Cuan *Vice President-Senior Analyst* Daniela.Cuan@moodys.com	EXT 141

LONDON	4420.7772.5454
Helen Francis *Vice President-Senior Credit Officer* Helen.Francis@moodys.com	4420.7772.5422

MOODY'S
INVESTORS SERVICE

Report Number: 125664

Author
Laura Schumacher

Senior Associate
Namsoo Lee

Senior Production Associate
Ginger Kipps

"Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality: Evaluating a Utility's Ability to Recover Costs and Earn Returns"

MOODY'S
INVESTORS SERVICE

SPECIAL COMMENT

Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality

Evaluating a Utility's Ability to Recover Costs and Earn Returns

Table of Contents:

Analyst Contacts:

NEW YORK 1.212.553.1653

Michael G. Haggarty 1.212.553.7172
Senior Vice President
Michael.Haggarty@moodys.com

Joseph Vinciguerra 1.212.553.4137
Associate Analyst
Joseph.Vinciguerra@moodys.com

William L. Hess 1.212.553.3837
Team Managing Director
William.Hess@moodys.com

» Analyst contacts continued on the last page

Summary

A utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings. In Moody's Regulated Electric and Gas Utilities Rating Methodology, published in August 2009 (the Rating Methodology), these concepts are incorporated as the second of four key factors utilized to determine credit ratings in the regulated utility sector. The criteria we consider when analyzing this factor include the statutory and regulatory provisions in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery of costs, precluding any possibility of legal challenges to rate increases or cost recovery mechanisms. Such strong statutory protections are most often found in very supportive and protected regulatory environments like Japan and Hong Kong, for example. In the U.S., however, the ability to recover costs and earn returns is much less certain and can be subject to intense public and sometimes political scrutiny, and such provisions vary among state jurisdictions. Consequently, the analysis of a U.S. based utility's cost recovery and return provisions is more complicated. This Special Comment discusses the criteria we use to determine how a utility is scored in the cost recovery and return factor in our ratings methodology.

One of the most referenced, but potentially misleading, indicators used to judge whether a particular utility is recovering its costs and earning an adequate return is its regulatory allowed return on equity. Although a high allowed return on equity can be associated with a higher earned return, this measure cannot be looked at in isolation but must be viewed in relation to a utility's cost recovery provisions that impact actual earned rate of return, like automatic adjustment clauses, the length of rate cases, and the degree of regulatory lag that may occur. Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risk of a utility, providing justification for a relatively low allowed rate of return. We believe this is one of several reasons why both allowed and requested ROE's have trended downward over the last two decades.

Moody's views automatic adjustment clauses, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk. Fuel adjustment clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. Many of these clauses are annual but they can also be semiannual, quarterly, or monthly. The scope of automatic adjustment clauses has expanded over the years and now covers costs as diverse as transmission, generation, renewable energy, environmental compliance, pensions and bad debt. Generally, the more of these clauses a utility has in place, the stronger its scoring should be on this ratings factor and the lower the credit risk.

Other considerations when analyzing cost recovery include the test year used, regulatory pre-approvals, and the inclusion of construction work in progress (CWIP) in rate base. Forward test years are generally better predictors of future utility conditions than historical test years, and their usage is more likely to reduce regulatory lag. Regulatory pre-approval of major capital expenditures, especially for large, complex projects like new nuclear plants, are also important in the maintenance of utility credit quality. Similarly, the inclusion of CWIP in rate base provides greater regulatory certainty, reduces the chance of rate shock or regulatory disallowance at the end of the construction period, and helps moderate financial pressure on a utility during a capital build cycle. Some of these concepts require a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service.

Other cost recovery related factors Moody's considers to be favorable to utility credit quality include granting of interim rate relief, which we view as an effective way to accelerate the lengthy and cumbersome rate case process, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. Decoupling mechanisms to "de-link" utility revenues and profits from volumes are essential to credit quality if energy efficiency and demand side management programs become more prevalent in the sector as anticipated. Finally, the option to issue cost recovery bonds to securitize large or unexpected costs, like those from storms, is another way that a utility can recover its costs and avoid the rate shock that could result if such costs are passed on to ratepayers over a limited time frame.

Introduction

In Moody's Rating Methodology, the cost recovery provisions a utility has in place, as well as the return it earns, are important determinants of a utility's rating and overall credit quality. These concepts are incorporated into the ratings methodology as the second of four key factors we use to determine ratings in the regulated electric and gas utility sector. A utility's ability to recover its costs and earn a return represents a significant 25% of the overall weighting[1] of the factors used to determine a utility's credit rating. Unlike Factor 1, Regulatory Framework, which considers the general regulatory environment under which a utility operates and the overall position of a utility within that regulatory environment, Factor 2 addresses in a more specific manner the ability of an individual utility to recover its costs and earn a fair return on invested capital.

1 The factor weightings shown in the rating methodology grid are approximate. The actual weight given to a factor in our assessment of an issuer's credit quality may differ based on the issuer's circumstances, and the scoring does not include every consideration that determines a rating.

TABLE 1

Regulated Electric and Gas Utility Rating Methodology

KEY RATING FACTORS AND WEIGHTINGS
1. Regulatory Framework – 25%
2. Ability to Recover Costs and Earn Returns – 25%
3. Diversification – 10%
4. Financial Strength and Liquidity – 40%

The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated electric and gas utilities, especially since the lack of timely recovery of costs has caused severe financial stress for utilities on several occasions. In five of the seven major investor owned utility defaults in the United States over the last 50 years, regulatory disputes culminating in insufficient or delayed rate relief for the recovery of costs and/or capital investments ultimately led to financial pressure and credit rating downgrades. The reluctance to provide rate relief in some cases reflected regulatory commission concerns about the impact of large rate increases on customers as well as concerns about the appropriateness and prudency of the relief being sought by a utility. Currently, given the utility industry's sizable capital expenditure requirements for infrastructure needs and environmental compliance, there is likely to be a growing and ongoing need for rate relief to recover these expenditures, at a time when economic conditions may limit the ability or willingness of regulators to provide this timely rate relief. Regulators also need to balance the amount of rate relief granted to utilities with consumers' ability to absorb these costs.

For regulated utilities, the criteria we consider in assessing Factor 2 include the statutory protections in place to insure full and timely recovery of prudently incurred costs. In their 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 and Hong Kong, for example.

More typically, however, and as is characteristic of most utilities in the U.S. and elsewhere in Asia, the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost adjustment clauses 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 in the A category 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 score 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.

Most of the utilities in Central and Eastern Europe (CEE) inherited oversized, outdated and underinvested infrastructure, built during previous communist regimes. Furthermore, those infrastructure assets are very often highly depreciated. Therefore, the main regulatory challenges for the CEE region lies rather in the area of full recovery of investment costs, including the establishment of appropriate regulatory asset bases and the determination of reasonable regulatory depreciation levels (which would be included in allowable costs to be recovered), rather than fine-tuning the actual level of return. Indeed, there is a very similar issue confronting South Africa, where there has been a long period of underinvestment in electricity assets. The approach towards the determination of the regulated asset base and treatment of asset revaluations differ significantly across the developing markets and could impact utilities' ability to generate sufficient funds for future investment in new assets.

The following is a discussion of the key factors we consider when scoring Factor 2, "Ability to Recover Cost and Earn Returns", in our Rating Methodology. The current Factor 2 scoring for the operating utilities in our rated universe is shown in Appendix A. These Factor 2 scores provide in indication of our current thinking. The scores are not intended to be static and continue to be monitored and modified as warranted to reflect changing conditions and circumstances, particularly as new rate cases are decided and cost recovery provisions evolve. In addition, when applied within the context of the Rating Methodology framework grid, the scores shown in Appendix A may be further modified by the use of a "strong" or "weak" designation.

Return on Equity and Regulatory Lag

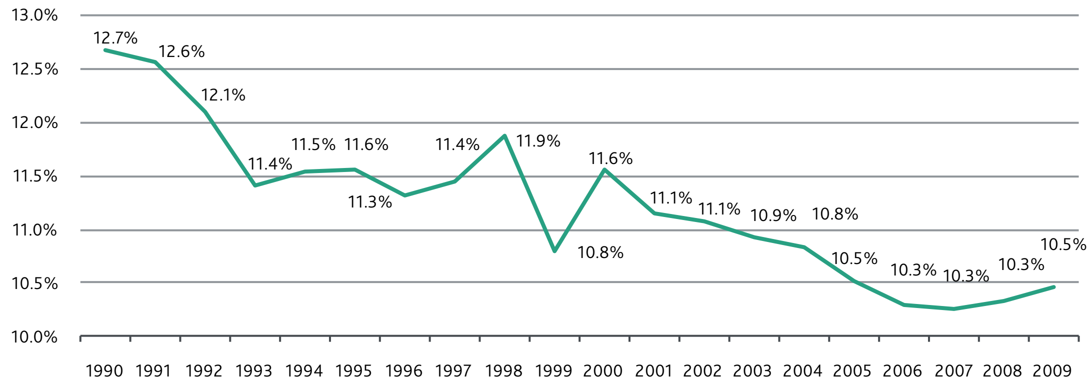
A utility's allowed return on equity (ROE) is one of the most obvious but potentially misleading statistics used to judge if a utility is recovering its costs and earning an adequate return. High ROE's are typically better than low ROE's, one reason that the timely, forward looking regulation of the Federal Energy Regulatory Commission (FERC) is viewed as more supportive, with ROE's that can be 12% or higher. In theory, if a utility's allowed return on equity is set at a high level, its earned return should also be high, leading to higher equity values, lower costs in relation to revenues, and ultimately higher credit ratings. This framework exists for some investor owned utilities, with high ROE's equating to good earnings and strong metrics, although this is not always the case. Earned ROE's are important in that they help to measure management's ability to operate their utility system within a given regulatory structure. A low allowed ROE is often associated with low earned ROE's, thereby affecting net income, lowering retained cash flow, depressing equity values, and raising financing costs.

However, the relationship between a utility's allowed return on equity and its ability to recover its costs and earn an adequate return is not as simple or clear cut as it may appear. A utility may have a low allowed ROE but be permitted to recover many of its operating costs through automatic adjustment clauses and other trackers, reducing risk and mitigating the impact of a low ROE. On the other hand, a utility may be permitted a high allowed ROE, but because of the higher than average risks associated with operating within this jurisdiction, the absence of such cost recovery provisions, overly long rate cases, or significant regulatory lag, may never actually earn its allowed return. According to the Edison Electric Institute, the average regulatory lag in the utilities industry is 11 months, close to where it has been for most of the last two decades. Adequate liquidity reserves on the part of utilities should mitigate some of the risks associated with regulatory lag.

While it is important to establish a link between a utility's regulatory allowed ROE and its automatic adjustment cost recovery clauses, it is also important to associate its authorized ROE with the sales forecast underlying the return. On its face, a high allowed ROE may appear favorable, although the return may be premised on a historic test year in which a high level of sales was achieved, which may not reoccur. This scenario could occur if there is a subsequent economic recession, unexpected financial shock, or lower usage on the part of the utility's customers due to high electric and/or gas rates or energy conservation. In such a case, a utility with a higher allowed ROE may be no better positioned than a utility with a lower allowed ROE based on a more achievable sales forecast. Allowed ROE's generate headline news, and market participants often gauge, at first blush, a utility's treatment in a rate case by this measure. However, the allowed ROE should not be viewed in isolation, but must be evaluated within the context of a utility's overall cost recovery provisions.

FIGURE 1

Average Awarded Electric ROE



Source: Regulatory Research Associates, a subsidiary of SNL Financial ,LLC, Edison Electric Institute

While regulatory lag has been stable, the long-term trend in allowed ROE's over the last two decades has been down, with the average allowed ROE falling from the 12% to 13% range in the early 1990's to the 10% to 10.5% range in recent years. In some cases, utility allowed ROE's have dropped below 10%. Not surprisingly, the average requested ROE has exhibited a similar trend, falling from as high as 13.5% in the early 1990's to approximately 11.2% in the first quarter of 2010. While some of the decrease in ROE's can be attributed to falling interest rates over the period, some can also be attributed to the other mechanisms that utilities have put in place to ensure timely cost recovery and maintain adequate returns, many of which are discussed below.

Some regulators view mechanisms such as cost recovery provisions and other automatic cost adjustment clauses as materially reducing the business and operating risk of some utilities, thereby justifying a lower return on equity. While there may be some merit to this argument, the relationship between these mechanisms and return on equity is complicated. Many of these provisions are "earnings neutral" but can have a cash impact, positive or negative, which could affect cash flow coverages and credit quality. Similarly, the increasing prevalence of formula based ratemaking and formula rate plans, where capital projects and other major revenue based changes are automatically incorporated into rates, have also caused some regulatory commissions to approve lower ROE's. However, a well structured formula rate plan could also lead to rate reductions if a utility is earning above its allowed range and in such cases, a lower allowed ROE may not be justified. Using ROE alone as a basis to compare utilities that operate under varying conditions and in different regulatory environments can be problematic and overly simplistic. Other considerations that may lead to widely different ROE's among utilities include the type of utility (whether vertically integrated or transmission and distribution), the mix of plants it operates, the size of its capital expenditure program, the risks associated with operating in a certain jurisdiction or building certain assets, demand and economic conditions within its service territory, and the utility's overall balance of debt and equity.

Fuel, Purchased Power and Other Automatic Cost Adjustment Clauses

Among the most common cost recovery provisions in the regulated utility sector are automatic adjustment clauses and other cost trackers (also referred to as riders or true-ups) for the recovery of costs outside of traditional base rate cases. The most prevalent type of such clauses are fuel adjustment clauses (FAC's) in the electric sector and purchase gas adjustments (PGA's) in the gas sector. These generally permit automatic changes in rates in response to movements in the price of fuels used in the generation of electricity and in the price of purchased gas for local distribution companies. Moody's views automatic adjustment clauses as supportive of utility credit quality and important in reducing utility cash flow volatility and liquidity requirements. These clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. They also reduce the level of regulatory uncertainty for the recovery of these costs by ensuring, through regulatory or statutory means, their recovery up-front.

Important considerations when analyzing such clauses include the frequency of true-up calculations and the period of time over which revenue variances are recovered. For example, Consolidated Edison Company of New York's purchased power cost variances are calculated monthly and recovered or refunded generally within one or two months. Some gas LDC's have quarterly gas cost adjustments; some vertically integrated utilities calculate fuel variances annually and recover these costs the following year, while others may recover some costs over a longer time period. In general, more frequent variance calculations and shorter recovery periods are considered more supportive of credit quality, limiting the potential for the accumulation of large deferral balances, the recovery of which could result in rate shock for consumers, as well as liquidity and working capital stress.

Adjustment Clauses as Regulatory Policy

Fuel adjustment clauses became prevalent in the U.S. in the 1970's when dramatically higher oil prices severely affected the cash flows of several utilities, when the industry was much more reliant on oil as a source of fuel for generation than it is today. During this time, oil prices rose so quickly that traditional base rate proceedings, with their lengthy time schedules, were unable to address cost recovery in a timely manner, severely stressing the cash flows of several utilities. Since that time, most U.S. states have permitted their utilities to automatically adjust fuel related rates outside of a formal base rate proceeding. In Missouri, one of the few states that historically did not have a fuel adjustment clause, legislation was passed in 2005 permitting the Missouri Public Service Commission to implement such a clause. In Ohio, fuel recovery was recently granted to AEP's Ohio Power subsidiary, although Duke Energy Ohio has had one in place for years.

Volume risk and purchase cost adjustments emerged as important regulatory topics in Central and Eastern Europe (CEE) only after the increase in the volatility of energy prices and unprecedented declines of energy consumption caused by the recent recession. The approach of respective CEE regulatory bodies varied from strong opposition to timely adjustments, mostly motivated by social considerations (i.e. Poland, Slovakia), to incorporation of automatic fuel and purchase adjustment mechanisms into regulation. Surprisingly, the regulatory regimes of Baltic countries, where the recession took the greatest toll, showed relatively solid resilience to political interference and allowed the local dominant electric utilities (the Latvian Latvenergo and the Estonian Eesti Energia) to pass through costs from fluctuating fuel input prices, thus allowing them to generate sufficient cash flows even in times of significant economic readjustment; this justifies their scoring of A in this factor.

In Korea, KEPCO's financial performance suffered significant deterioration in 2008 as a result of exposure to contracted high fuel costs and sharp depreciation of the Korean Won. The government stepped in and approved a 4.5% tariff increase and a KRW668 billion one-off subsidy to offset its losses due to high fuel costs and currency devaluation. The government is also considering implementing an automatic cost pass through mechanism in due course.

Automatic adjustment clauses are typically aimed at mitigating the effects of highly variable costs, such as fuel and purchased power, which are typically the largest component of utility operating expenses. These costs have been particularly volatile over the last several years, a time when the industry has become more exposed to both natural gas and coal prices. This exposure was again highlighted in late 2005 when two major hurricanes severely disrupted natural gas production in the Gulf Coast region, leading to a sudden and sustained increase in natural gas prices. Such costs are for the most part out of the utility's control, although some try to manage them by hedging their fuel supply to some degree. However, both the magnitude and volatility of these costs make fuel adjustment clauses one of the more widely used and effective cost recovery mechanisms in the industry.

In some cases, fuel adjustment clauses may be limited in scope or subject to regulatory review to ensure that the costs that are incurred are prudent. Some states allow rate adjustments within certain ranges or bandwidths, with any costs incurred outside of these ranges deferred for recovery in subsequent base rate cases. Cost deferred and recovered through later base rate cases depress cash flow and inevitably add to regulatory lag, a short-term issue that should not negatively affect long-term credit quality

Fuel adjustment clauses, which also include purchased power costs, have also become critical to transmission and distribution utilities that no longer own generation assets following the deregulation of electricity markets in their states. Many of these companies are responsible for procuring power for their retail customers as part of their Provider of Last Resort or POLR obligations and, as a result, are responsible for procuring their generation requirements in the wholesale power markets. The lack of a prompt and timely generation cost adjustment clause or similar pass-through mechanism can have a detrimental effect on transmission and distribution utility cash flows and credit quality.

Automatic adjustment clauses and other pass-through mechanisms have been expanded over the years and now cover costs as diverse as transmission, new generation, renewable energy, environmental compliance costs, demand side management and energy efficiency costs, pensions, and bad debt expenses. These clauses may also be put in place for more unusual or extraordinary costs such as those incurred as a result of hurricanes or ice storms. In some states, changes in interest expense relative to what had been incorporated into existing rates have also been covered by such clauses. Like fuel and purchased power adjustment clauses, these other clauses are likely to increase the likelihood of timely recovery of prudently incurred costs, reduce regulatory uncertainty, and lead to a higher score for a utility's cost recovery factor in our ratings methodology.

Forecast Risk – Historical Versus Forward Test Years

In most utility ratemaking procedures, the selection of a test year is an important consideration in determining both the level of adjustments to rates that may be necessary later and the degree of regulatory lag the may result. A test year is the base year in which a forecast of a utility's operations and investment requirements over a twelve month period is devised. It is supposed to be representative of what costs will be incurred by a utility during an upcoming period, and establish what additional rate adjustments a utility will need to cover costs and earn an adequate rate of return. Depending on the regulatory provisions of a particular state, utilities are generally required to use either a historical test year or a future test year. In some cases, a combination or "hybrid" of these two test year periods can be used, with "known and measurable" adjustments.

A historical test year utilizes a twelve month period before the current rate filing as the basis for determining future rates. Some state regulatory commissions prefer historic tests years because the information used in determining rates is based on actual data that can be easily measured and analyzed.

However, in situations where industry conditions are changing rapidly, such as when costs are increasing or capital expenditures growing, historical test years are generally less useful as an accurate data point for setting future rates. In addition, the use of historical test years can contribute to regulatory lag in that a utility must usually file another rate case to recover those costs not accurately predicted with the use of the historical test year. As a result, utilities that use historical test years typically do not earn their allowed rate of return on an ongoing basis and experience persistent regulatory lag in the recovery of costs.

The use of a forward (or future) test year, while not a perfect predictor of future utility revenue requirements, strives to use the most timely and up-to-date information available in setting rates. Forward test years are typically based on forecasts of future costs and expenses, often leading to a high degree of scrutiny by regulators on the financial models and assumptions used in creating these forecasts. While all forecasts have limitations, forward test years are generally better predictors of future utility conditions than historical test years, especially where there are rapidly changing industry conditions. Forward test years can better incorporate current and expected economic conditions, a utility's capital expenditure budget going forward, and projected changes to a utility's customer base or load growth forecasts, for example. Moreover, forward test years help to reduce regulatory lag and ensure that a utility earns closer to its allowed rate of return. As a result, from a credit standpoint, Moody's views the use of forward test years as more supportive of utility credit quality than historical test years.

Regulatory Pre-Approvals

The utilities industry is in the midst of a substantial capital expenditure program, with significant investment planned in all aspects of its business, including generation, transmission, and distribution, as well as for substantial environmental compliance expenditures. Because of the size and complexity of many of these projects, Moody's places a high degree of emphasis on the regulatory certainty for the recovery of such costs, which is critical for the maintenance of utility credit quality. For some of these projects, especially when considering added uncertainty related to the economy and the timing of future laws and regulations related to carbon, it will be viewed as a significant credit positive if utilities are able to obtain regulatory support for recovery in advance. This would serve to limit regulatory risk associated with eventual disallowance or nonrecovery of already expended costs. Some U.S. states, including Idaho, Iowa, Virginia, and Wisconsin, have passed legislation pre-approving some generation costs and outlining cost recovery provisions for new plant construction, which Moody's considers to be a positive regulatory development for the utilities in those states. In India, the construction of Ultra Mega Power Projects do not have any cost recovery provisions, but are rather based on competitive tariff structures. Pre-approval of purchased power agreements would also be considered positively from a credit standpoint.

Approval of future project capital expenditures in advance requires a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service. In order for a state regulatory commission to pre-approve costs for a large and complex project, it is necessary for the commission and commission staff to gain an understanding of the project, including the need for the project, the construction budget, and the financing plan. Some projects underway right now, such as new nuclear construction, are expensive, complex, and multi-year in scope, and may not have been undertaken at all if regulators were not on board with the prudency of their projected costs and timetable in advance.

Regulatory pre-approval of utility capital expenditures may include incentives, mandated completion dates, or caps on the aggregate amount of recovery, giving state regulators some control over the ultimate costs and thus limiting ratepayer exposure in the event there are cost overruns or delays. In some cases, utilities may seek pre-approval for capital expenditures on a regular basis, such as annually or semi-annually, throughout the project's construction period. For example, for the recovery of costs related to Georgia Power's new nuclear construction project at its Vogtle plant site, the utility files a semi-annual construction monitoring report with the Georgia Public Service Commission (GPSC), with the GPSC reviewing and approving project costs on an ongoing basis. South Carolina Electric & Gas has a similar arrangement with the South Carolina Public Service Commission (SCPSC) for new nuclear construction at its Summer plant site. In order for such a pre-approval arrangement to be effective, however, state commissions need to have the time, ability, and resources to properly evaluate a complex project's construction progress, as well as any potential delays or problems that may arise. The Indiana Utility Regulatory Commission, for example, has an engineer advising them on Duke Indiana's Edwardsport project. Moody's views such collaborative utility-regulatory commission relationships as positive and important in insuring that prudent project costs are eventually recovered. They also serve to limit, but not fully protect against, the risk that there will be significant stranded, disallowed or otherwise unrecovered expenditures.

Construction Work in Progress (CWIP) in Rate Base/Concurrent Recovery

"Construction work in progress" (CWIP) represents the cost of capital projects that are under construction but not yet in service and considered "used-and-useful" in the provision of electric and/or gas service. Under traditional utility ratemaking, these costs cannot be included in customer rates until a project is completed and fully operational. However, because of the long lead times and large cost of many utility construction projects, some utilities are permitted by regulators to include CWIP in rate base, allowing it to earn a cash return on the project while it is under construction. The alternative would be for a utility to accumulate the financing costs on CWIP over the construction period (called "allowance for funds used during construction" or AFUDC) and include them in rates when the project is completed. Proponents of this approach generally argue that it is appropriate for utility ratepayers to pay only for projects that are in use and currently benefiting them through the provision of electricity and/or gas.

Moody's views the inclusion of CWIP in rate base as supportive of utility credit quality. It helps moderate the financial pressure of the incremental construction related debt by providing a cash return during lengthy, sometimes uncertain, and potentially delayed construction periods. It also allows a project's costs to be gradually incorporated into rates rather than all at once at the conclusion of construction, when a large and potentially unpopular one-time rate increase may be required. The resulting rate shock could lead to further delays in the recovery of these costs or political/legislative intervention aimed at limiting or denying utility cost recovery altogether.

It should be noted that not all CWIP recovery provisions are the same. Some state regulatory commissions only allow a portion of CWIP to be included in rate base, some only allow a debt return, while others allow a full weighted average cost of capital return. From a credit perspective, inclusion of all CWIP in rate base at a full weighted average cost of capital return would be considered the most supportive CWIP recovery provision.

Whether to allow CWIP in rate base became a significant issue several years ago, particularly during the last round of nuclear construction in the 1970's, when a number of utilities were engaged in major nuclear construction projects and substantial cost overruns were commonplace. This was also an era of high inflation and high interest rates, exacerbating the rate impact of allowing CWIP in rate base. Because of this experience, a few states actually passed laws prohibiting utilities from including CWIP in rate base, some of which are still on the books today. The issue has again come to the forefront with the advent of major new nuclear construction in the U.S., and also because of large capital expenditure plans for transmission, renewable energy projects, integrated gasification combined-cycle (IGCC) plants, and environmental compliance requirements. Although the treatment of CWIP by individual state regulatory commissions varies, most states do allow for the inclusion of some or all of CWIP in rate base, a credit positive. Those states that do not allow the inclusion of CWIP in rate base, either by law or by recent commission decision, are listed below.

TABLE 2

States Not Allowing CWIP in Rate Base

LEGALLY PROHIBITED	DENIED BY COMMISSION
Connecticut	Arizona
Missouri	Nebraska
New Hampshire	Oklahoma
Oregon	Rhode Island
Pennsylvania	

The inclusion of CWIP in rate base is an especially important credit supportive measure for those utilities in the process of constructing new nuclear plants. In Georgia and Florida, for example, legislation passed over the last few years allows utilities in both states to earn a cash return on CWIP for new nuclear construction. For Georgia Power, the inclusion of CWIP in rate base and the recovery of financing costs on its new Vogtle nuclear construction project reduced the project's in-service cost to $4.5 billion from $6.4 billion. Similarly, in South Carolina, the Public Service Commission has authorized South Carolina Electric & Gas to earn a cash return on CWIP associated with new nuclear construction in that state. In contrast, in early 2009, Ameren subsidiary AmerenUE suspended efforts to build a new nuclear plant in Missouri after legislation allowing CWIP in rate base was not passed by the Missouri General Assembly.

As previously mentioned, the less favorable alternative to inclusion of CWIP in rate base from a credit standpoint is allowance for funds used during construction (AFUDC) accounting treatment for construction projects. With AFUDC, capital projects do not earn a cash return during the construction phase, but do when they become used and useful. Because of the long lead times and large cost of many utility construction projects, this can place great financial and liquidity pressure on utilities. Under AFUDC accounting conventions, a utility's earnings are made whole by non-cash earnings, offsetting the incremental debt and equity capital costs incurred to finance the projects. While there is no earnings impact on a utility income statement, cash flow generally lags while debt mounts, a credit negative. Some opponents to AFUDC treatment argue that rate payers generally face a larger one-time rate increase under this approach than if CWIP treatment was applied.

Interim Rate Relief

Because of the length of base rate cases, with many lasting 12 months and some as long as 18 months, interim rate relief is often an effective way to accelerate rate relief, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. While some states allow utilities to petition for interim rate relief, others only permit such relief in extraordinary or emergency situations, limiting its use to unusually dire circumstances. Interim rate relief is also difficult for state regulators to grant when there are poor economic conditions in a utility's service territory, and some requests for interim rate relief are declined for these reasons. Because interim rate relief has a positive impact on utility cash flows and coverage metrics and reduces regulatory lag, Moody's views interim rate relief as a positive credit consideration. The existence of a maximum timeframe for decisions on interim (or general) rate cases is another important credit consideration. If there is no statutory time limit for rendering such rate case decisions, regulatory lag can result.

In Florida, utilities may request an interim rate increase only if they have petitioned the Florida Public Service Commission (FPSC) for a permanent base rate increase. In its most recent rate case, for example, Progress Energy Florida requested and was granted an interim rate increase to recover the costs of repowering one of its generating units to natural gas from oil. The interim rates were put in effect during the course of the base rate proceeding, which in Florida takes about nine months. Interim rates are credited back to customers, with interest, if the FPSC determines in its final rate decision that the interim rates were not justified. In Hawaii, interim rates must be enacted within 11 months of filing, but there is no statutory time limit for a final decision. As such, the majority of Hawaiian Electric rate decisions in recent years have been interim decisions.

In West Virginia, Appalachian Power and Wheeling Power, both subsidiaries of American Electric Power (AEP), requested an interim rate increase of $180 million in April 2009, out of an overall $442 million rate increase request, for fuel, purchased power, and environmental compliance project expenses. Because of sharply higher fuel costs, the company was paying more for fuel than it was receiving in existing rates and hoped the interim rates would offset a growing fuel underrecovery. On June 4, 2009, the Public Service Commission of West Virginia denied the request, citing the potential for financial hardship on customers, especially during currently difficult economic times. The denial of interim rate relief is considered a credit negative in that it added to fuel underrecoveries and increased regulatory lag at the utilities.

Volume Risk and Decoupling

There has been a great deal of emphasis and attention in recent years given to energy efficiency and demand side management programs aimed at reducing the consumption of electricity and natural gas both because of environmental concerns and for economic reasons. For utilities these efforts represent a potential threat to cost recovery because under traditional rate of return regulation, utility revenues are a function of the volume of power and energy is sold, i.e. all or a portion of the utility's fixed costs are recovered through volumetric charges. Consequently, utilities that are dependent on volume are, in fact, economically motivated to encourage higher energy usage instead of conservation and energy efficiency. Decoupling is aimed at "de-linking" a utility's revenues and profits from volume and at the same time compensating utilities for promoting less energy use.

Decoupling has become more prevalent over the last year since the Federal government's economic stimulus bill was passed in February 2009. That bill provides significant funding to states to promote and encourage energy efficiency programs, but only in the event there are incentives in place for utilities themselves to encourage and promote such programs. There are still relatively few states with decoupling measures in place for electric utilities, although they have been more common for gas utilities. Moody's views decoupling measures as important to the maintenance of utility credit quality in states where energy efficiency and demand side management programs could put pressure on utility sales volumes, operating margins, and cash flow coverage metrics.

TABLE 3

Selected States With Decoupling Measures in Place

ELECTRIC DECOUPLING	GAS DECOUPLING
California	Arkansas
Connecticut	California
Idaho	Colorado
Maryland	Illinois
Massachusetts	Indiana
Michigan	Maryland
New Hampshire	Massachusetts
New York	Michigan
Oregon	Minnesota
Vermont	New Jersey
	New York
	Nevada
	North Carolina
	Ohio
	Oregon
	Utah
	Virginia
	Washington
	Wisconsin
	Wyoming

The state of California was at the forefront of states adopting decoupling as far back as 1982, when it put an Electric Revenue Adjustment Mechanism in place, which de-linked utility revenues from utility sales to promote energy conservation. Other states have introduced decoupling more recently, including Idaho, Maryland, Massachusetts, and New York. Some states have partial decoupling measures in place, such as New Hampshire, which allows decoupling for generation and transmission, but not for distribution. Hawaii has recently approved a decoupling mechanism, which is most similar to the California model, but it has yet to be fully implemented into electric rates. Many more states are considering decoupling measures and Moody's expects such measures to become increasingly prevalent as energy efficiency and demand side management programs are increasingly emphasized.

Cost Recovery Bonds (Securitization)

Since the late 1990's, legislatively approved stranded cost, storm cost, and other cost recovery bonds have been issued to reimburse utilities for costs related to deregulation, hurricanes, environmental compliance, and energy supply. In its simplest form, a securitization is a type of irrevocable rate order that authorizes and dedicates a stream of cash flow to service bonds issued to reimburse utilities for specific costs. Such bonds were originally issued to compensate utilities for stranded costs following the deregulation of the energy markets in some states several years ago. More recently, storm-related securitizations have been completed following active hurricane seasons in 2004, 2005 and 2008 along the Gulf Coast region and in Florida. Securitization bonds have also been issued to finance environmental compliance costs in West Virginia.

Cost recovery bonds represent another way that regulatory commissions and state legislatures can assure that a utility receives adequate recovery for sometimes large and unanticipated capital expenditures, while avoiding the rate shock that could result from passing through all these costs over a limited time frame. Instead, cost recovery bonds allow these costs to be spread out and financed over a multi-year period. Customers benefit from the low financing costs that characterize such bonds, since the special purpose entities issuing the bonds are typically rated Aaa, and the utility is reimbursed for the costs it incurred fairly quickly when the bonds are issued, reducing regulatory lag. However, Moody's notes that some storm cost recovery bonds have been issued as long as two to three years after the costs have been incurred, in some cases due to the need to pass legislation authorizing such bonds. Such legislation is necessary to insure that the collection of the cost recovery bond surcharge is statutorily protected, irrevocable, and non-bypassable. Moody's views utilities that have the option of issuing cost recovery bonds in the event of large, unexpected, or extraordinary costs more favorably from a credit point of view.

Conclusion

Cost recovery provisions and a utility's ability to earn an adequate return are important considerations in determining credit quality and credit ratings in the regulated utility sector, so much so that they account for a significant 25% weighting when determining utility credit ratings under our Rating Methodology. Among the provisions we consider when judging this factor include a utility's ability to earn its allowed return on equity, which must be examined in conjunction with its actual earned return on equity resulting from its overall cost recovery provisions. These provisions could include automatic adjustment clauses, the use of a forward test year, regulatory pre-approval of major capital expenditures, construction work in progress (CWIP) in rate base, interim rate relief, decoupling, and the option of issuing cost recovery or securitized bonds to recovery large or unexpected costs. The presence of most or all of these provisions is likely to lead to a higher score for the cost recovery and earned return factor in our ratings methodology.

Appendix A: Current Factor 2 Scoring for the operating utilities in Moody's rated universe

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
Tennessee Valley Authority	Chubu Electric Power Company, Incorp.	Alabama Power Company	ALLETE, Inc.	Companhia Energetica de Minas Gerais - CEMIG	Perusahaan Listrik Negara (P.T.)
	Chugoku Electric Power Company, Incorp.	Consumers Energy Company	Appalachian Power Company	Cemig Geracao e Transmissao S.A.	
	CLP Power Hong Kong Limited	Dayton Power & Light Company	Arizona Public Service Company	Companhia Paranaense de Energia - COPEL	
	Electric Power Delevopment Co., Ltd.	Detroit Edison Company (The)	Black Hills Power, Inc.	EDP – Energias do Brasil	
	Hokkaido Electric Power Company, Incorp.	Duke Energy Carolinas, LLC	Central Vermont Public Service Corp.	Empresas Publicas de Medelin E.S.P.	
	Hokuriku Electric Power Company	Duke Energy Indiana, Inc.	Cleco Power LLC	Entergy Texas	
	Kansai Electric Power Company, Incorp.	Florida Power & Light Company	Columbus Southern Power Company	Eskom Holdings Ltd	
	Kyushu Electric Power Company, Incorp.	FortisBC Inc	Duke Energy Kentucky, Inc.	Furnas Centrais Electricas S.A.	
	Okinawa Electric Power Company, Incorp.	Georgia Power Company	Duke Energy Ohio, Inc.	Israel Electric Corporation Limited (The)	
	Osaka Gas Co., Ltd.	Gulf Power Company	EDA - Electricidade dos Acores, S.A.	Light S.A.	
	Tokyo Electric Power Company, Incorp.	Indianapolis Power & Light Company	Eesti Energia AS	NTPC Limited	
	Tokyo Gas Co., Ltd.	Interstate Power & Light Company	El Paso Electric Company	Tata Power Company Limited (The)	
		Kentucky Utilities Co.	Empire District Electric Company (The)	Union Electric Company	
		Louisville Gas & Electric Company	Empresa de Electricidade da Madeira, S.A.		
		Madison Gas and Electric Company	Entergy Arkansas, Inc.		
		MidAmerican Energy Company	Entergy Gulf States Louisiana, LLC		
		Mississippi Power Company	Entergy Louisiana, LLC		
		Northern Indiana Public Service	Entergy Mississippi, Inc.		
		Northern States Power Company (Minnesota)	Entergy New Orleans, Inc.		
		Northern States Power Company (Wisconsin)	Hawaiian Electric Company, Inc.		
		Oklahoma Gas & Electric Company	Hydro-Québec		
		Pacific Gas & Electric Company	Idaho Power Company		
		Progress Energy Carolinas, Inc.	Indiana Michigan Power Company		
		Progress Energy Florida, Inc.	Kansas City Power & Light Company		
		Public Service Company of Colorado	Kentucky Power Company		
		South Carolina Electric & Gas Company	Korea Electric Power Corporation		
		Southern California Edison Company	Latvenergo		
		Southern Indiana Gas & Electric	Monongahela Power Company		
		Superior Water, Light and Power Company	Nevada Power Company		

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
		Tampa Electric Company	NorthWestern Corporation		
		Virginia Electric and Power Company	Ohio Power Company		
		Wisconsin Electric Power Company	Otter Tail Corporation		
		Wisconsin Power and Light Company	PacifiCorp		
		Wisconsin Public Service Corporation	Portland General Electric Company		
			Public Service Company of New Hampshire		
			Public Service Company of New Mexico		
			Public Service Company of Oklahoma		
			Puget Sound Energy, Inc.		
			Sierra Pacific Power Company		
			Southwestern Electric Power Company		
			Southwestern Public Service Company		
			Taiwan Power Company Limited		
			Tenaga Nasional Berhad		
			Tucson Electric Power Company		
			UNS Electric		

T&D Utilities

Aa	A	Baa	Ba	B
Hong Kong and China Gas Co. Ltd	AEP Texas Central Company	Atlantic City Electric Company	AES Eletropaulo	Edenor S.A.
Oman Power and Water Procur. Co.	AEP Texas North Company	Baltimore Gas and Electric Company	AES El Salvado Trust	
	CenterPoint Energy Houston Electric, LLC	Central Illinois Light Company	Bandeirante Energia S.A.	
	Central Hudson Gas & Electric Corporation	Central Illinois Public Service Company	Cemig Distribuicao S.A.	
	Central Maine Power Company	Cleveland Electric Illuminating Company (The)	Centrais Eletricas do Para S.A.	
	Consolidated Edison Company of New York, Inc.	Commonwealth Edison Company	Centrais Eletricas Matogrossenses S.A.	
	FortisAlberta Inc.	Connecticut Light and Power Company	Comp. de Ener. Eletr. do Est. do Tocantins	
	Hydro One Inc.	Delmarva Power & Light Company	Espirito Santo Centrais Eletricas - ESCELSA	
	Massachusetts Electric Company	Duquesne Light Company	Ejesa S.A.	
	New England Power Company	Illinois Power Company	Empresa Electrica de Guatemala, S.A.	
	Newfoundland Power Inc.	Jersey Central Power & Light Company	Energisa Paraíba-Dist. de Energia S.A.	
	Niagara Mohawk Power Corporation	Metropolitan Edison Company	Energisa Sergipe - Dist. de Energia S.A.	
	NSTAR Electric Company	Narragansett Electric Company	Gas Authority Inida Limited	
	Oncor Electric Delivery Company	New York State Electric and Gas Corporation	Light Serviços de Eletricidade S.A.	
	Orange and Rockland Utilities, Inc.	Ohio Edison Company	Perusahaan Gas Negara	
	Public Service Electric and Gas Company	PECO Energy Company	Rede Energia	
	San Diego Gas & Electric Company	Pennsylvania Electric Company	Rio Grande Energia S.A. - RGE	
		Pennsylvania Power Company	Towngas China Co. Ltd	
		Potomac Edison Company (The)	Xinao Gas Holdings Ltd	
		Potomac Electric Power Company		
		PPL Electric Utilities Corporation		
		Rochester Gas & Electric Corporation		
		Texas-New Mexico Power Company		
		Toledo Edison Company		
		United Illuminating Company		
		West Penn Power Company		
		Western Massachusetts Electric Company		

Transmission Only Utilities

A
American Transmission Company LLC
American Transmission Systems
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company
Trans-Allegheny Interstate Line Company

Local Gas Distribution Companies (LDCs)

Aa	A	Baa	Ba	B
Terasen Gas (Vancouver Island) Inc.	Atlanta Gas Light Company	Berkshire Gas Company	Gas Natural Ban S.A.	Camuzzi Gas Pampeana S.A.
	Bay State Gas Company	Boston Gas Company		Metrogas S.A.
	Brooklyn Union Gas Company, The	Cascade Natural Gas Corp.		
	Indiana Gas Company, Inc.	Cia de Gas de São Paulo - COMGAS		
	Michigan Consolidated Gas Company	Colonial Gas Company		
	New Jersey Natural Gas Company	Connecticut Natural Gas Corporation		
	Northwest Natural Gas Company	Laclede Gas Company		
	Piedmont Natural Gas Company, In	North Shore Gas Company		
	Public Service Co. of North Carolina, Inc.	Northern Illinois Gas Company		
	South Jersey Gas Company	Peoples Gas Light and Coke Co.		
	Southern California Gas Company	SEMCO Energy, Inc.		
	Terasen Gas Inc.	Source Gas LLC		
	Wisconsin Gas LLC	Southern Connecticut Gas Company		
		Southwest Gas Corporation		
		UGI Utilities, Inc.		
		UNS Gas		
		Washington Gas Light Company		
		Yankee Gas Services Company		

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» contacts continued from page 1

Analyst Contacts:

NEW YORK	1.212.553.1653
Jim Hempstead *Senior Vice President* James.Hempstead@moodys.com	1.212.553.4318
A.J, Sabatelle *Senior Vice President* Angelo.Sabatelle@moodys.com	1.212.553.4136
Mihoko Manabe *Vice President – Senior Credit Officer* Mihoko.Manabe@moodys.com	1.212.553.1942
Allan McLean *Vice President – Senior Credit Officer* Allan.McLean@moodys.com	1.416.214.3852
Kevin Rose *Vice President – Senior Analyst* Kevin.Rose@moodys.com	1.212.553.0389
Laura Schumacher *Vice President – Senior Analyst* Laura.Schumacher@moodys.com	1.212.553.3852
Scott Solomon *Vice President – Senior Analyst* Scott.Solomon@moodys.com	1.212.553.4358
Natividad Martel *Analyst* Natividad.Martel@moodys.com	1.212.553.4561
Jim O'Shaughnessy *Analyst* Jim.O'Shaughnessy@moodys.com	1.212.553.1607
Wesley (Wes) Smyth *Vice President – Senior Accounting Specialist* Wesley.Smythe@moodys.com	1.212.553.2733
HONG KONG	1.852.3551.3077
Jennifer Wong *Assistant Vice President–Analyst* Jennifer.Wong@moodys.com	1.852.3758.1373
SAO PAULO	5511.3043.7300
Jose Soares *Vice President-Senior Analyst* Jose.Soares@moodys.com	5511.3043.7339
BUENOS AIRES	5411.4816.2332
Daniela Cuan *Vice President-Senior Analyst* Daniela.Cuan@moodys.com	EXT 141
LONDON	4420.7772.5454
Helen Francis *Vice President-Senior Credit Officer* Helen.Francis@moodys.com	4420.7772.5422
TOKYO	81.3.5408.8100
Kenji Okamoto *Vice President- Senior Analyst* Kenji.Okamoto@moodys.com	81.3.5408.4219

Report Number: 122304

Author
Michael G. Haggarty

Associate Analyst
Joseph Vinciguerra

Senior Associate
John Grause

Production Associate
Sylviane Grant

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INVESTORS SERVICE