Figure 4 shows a broad categorization of the relative riskiness of unregulated activities that are commonly part of the business of electric utility companies. These are grouped into broad categories of high, medium and low business risk. These classifications are general and do not fully capture individual company characteristics or differences in regional markets. For example, uncontracted wholesale power generation is likely to be riskier in the US, where the market is fragmented, than in Germany, where a smaller number of companies have relatively large market shares.

This categorization of the risks of unregulated businesses can be summarized as follows:

Category 1 – High

Category 2 – Medium

Category 3 – Low

Figure 4

High Business Risk
Merchant power generation that is located in highly competitive markets or merchant power generation that is high-cost and is not sold under long-term contract to a highly creditworthy counterparty.
Energy trading and marketing that is speculative or market-making in nature.
Investments in unregulated international power assets in unfamiliar markets.
Various investments outside the core area of industry expertise. Frequent areas for such diversified investment include: telecommunications; oil and gas exploration and production; and real estate development.
Medium Business Risk
Merchant power generation in markets in which competition is limited by the large market share of each participant, by geographic isolation, or [illegible] of critical production and transmission infrastructure, or because the unregulated generation is relatively low-cost.
Affiliated [illegible] generation and supply businesses that sell primarily under contract to the regulated utility or within the utility's core market area.
Energy trading and marketing that is strictly limited to trading around the utility's physical generation and transmission assets, with little or no [illegible] trading.
[illegible] or natural gas pipelines that are closely integrated with the utility's regulated generation business as the source of fuel for [illegible] power plants.
Low Business Risk
Unregulated electricity generation that is wholly sold under long-term contract to highly creditworthy counterparties which assume all risk of fluctuation in the market prices of fuel and electricity.
Unregulated [illegible] electricity generation that is very well insulated from competition because of the utility's high market share or [illegible] control of the key infrastructure assets that are needed to generate or deliver electricity.
Selling and [illegible] customer equipment that is related to the core utility business, or contractual arrangements to manage customers' fuel and electricity needs, under which the customer retains all risk of fluctuation in market prices.

High-Business-Risk Unregulated Activities

This higher business risk category includes merchant generation in highly competitive markets, energy trading and marketing that is speculative or market-making in nature, and unregulated electric generation investments in unfamiliar or poorly developed markets.

Merchant energy is considered to include unregulated power generation for which the output is not sold under long-term contract with a creditworthy counterparty. In the merchant model, power is sold into the competitive or merchant market, and cash flows are subject to market price volatility. The absence of contracts results in less predictable cash flows and higher business risk.

Energy marketing and trading is a related activity that often has a high level of risk associated with it. There can be substantial differences in the riskiness of energy trading and marketing, depending upon the strategy and size of this activity. Speculative trading activity has the potential to produce large swings in income or loss, has limited risk transparency, and may result in large swings in liquidity needs. Trading and marketing activities that are ancillary to a core utility business (trading around the physical assets) are considered to be much less risky than pure proprietary or speculative trading. However, all energy trading is viewed as having a higher business risk profile than regulated activities.

A number of other investments outside the core sector of industry expertise are likely to fall into the high business risk category. Such areas of diversification may include telecommunications, equity investments in leases, oil and gas exploration and production, miscellaneous manufacturing and real estate development.

The six core ratios[1] are as follows:

Primary:

1. Retained Cashflow[2] / Adjusted gross debt[3]
2. FFO / Adjusted gross debt
3. FFO / Interest
4. Adjusted gross debt / Regulated Asset Value[4], or Capitalization

Secondary:

5. EBITDA Margin
6. Retained Cashflow / Capex

While other factors considered in this report may outweigh pure quantitative analysis, it is possible to provide broad guidance on the ratio ranges that may generally be seen at different rating levels.

In general, other factors – such as the degree of likely support from a sovereign – tend to outweigh financial ratios for companies operating in a very low business risk environment such as Japan or Finland. Similarly, considerations such as an undeveloped regulatory framework, potential political risk or relatively opaque corporate governance may outweigh financial ratios for companies operating in a high business risk environment. Our analysis also considers prospective future performance, which may differ from historic ratios.

Financial ratios are more useful for companies operating in a low business risk environment where there is a high degree of regulated activities and a supportive regulatory system. This might include the UK, US transmission and distribution utilities (T&Ds), Canada or many European countries. Medium-business-risk operating environments would include US integrated utilities.

As noted above, this is a local industry found globally rather than one where companies compete with each other outside their own local area. While companies in, say, Japan or in the US or in Germany, all tend to have similar profitability dynamics, there is little global similarity. Hence, measures of profitability are helpful in rank-ordering companies within their own local regulatory operating environment, but not helpful as a global indicator of ratings.

Measures of interest cover, cashflow to debt and balance sheet measures tend to be more consistent across the whole universe of global regulated electric utility companies.

As a guide, the following primary ratios, as set out in Figure 5, might be expected for a utility company without factoring in any uplift for possible sovereign support.

Figure 5

	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Business risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
FFO Int. cov. (X)	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
FFO/Debt (%)	>30	>22	22-30	12-22	13-25	5-18	<13	<5
RCF/Debt (%)	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Debt/Capital (%)	<40	<50	40-60	50-75	50-70	60-75	>60	>70

Other utility-specific issues relevant to quantitative analysis

Power Purchase Agreements ("PPAs")

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

1. *Please see Appendix 2 for definitions.*
2. *Retained Cashflow (RCF) is FFO less dividends*
3. *Moody's concentrates on gross debt but will also consider net debt ratios if the cash is clearly being held for future debt maturities or for reasons such as hedging. A good example of this would be a company that has hedged the exchange risk of an overseas investment with the local currency debt despite having surplus cash at the parent level. In such cases, the net ratio will take predominance over the gross ratio.*
4. *The Regulated Asset Value (RAV) or Regulated Asset Base (RAB)*

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

Factors determining the treatment of PPAs

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

- Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.
- Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- Price considerations: The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it does not require it for its own customers, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may have a material impact on the utility's cash flow.
- Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totalled 42.5% of its operating costs in FY2004. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.
- Risk-sharing: Utilities that own plant bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.
- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's adjusted debt, in the same way as other off-balance sheet items.[5]

5. See "*The Analysis of Off-Balance Sheet Exposures – A Global Perspective*", *Rating Methodology, July 2004.*

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

Methods of accounting for PPAs in our analysis

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

Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the obligations of the utility.

Annual Obligation x 8: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of eight. This method is sometimes used in the capitalization of operating leases.[6] This method may be used as an approximation where the analyst determines that the obligation is significant but cannot be quantified otherwise due to limited information.

Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the adjusted obligations of the utility. The discount rate used will be the cost of capital of the utility.

Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility will be added to its total obligations.

Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

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

Nuclear liabilities

In several integrated European companies, nuclear power generation form a significant component of their power generation activities. These activities will usually be unregulated but comprise an important element of the analysis of these companies. The analysis is complicated by the lack of consistency in treating nuclear related items in different countries.

In general, nuclear waste management obligations are factored into debt using Moody's methodology for unfunded pensions. This recognizes the uncertainty of final amounts and timing in assessing the likely call on future cash flows. The methodology simulates a pre-funding of the obligation, taking into account access to the equity market and management's probable funding strategy. The existing debt-to-equity mix is generally used as a starting point.

For ratio analysis purposes, Moody's excludes reprocessing provisions from its calculation of total nuclear liability provisions if such provision is expected to remain a permanent component of the nuclear liabilities that will continually be replenished as fuel is used in the production process in line with the expectation that nuclear power will remain an important component of the company's generation portfolio for the foreseeable future.

For nuclear provisions that are recorded and funded on balance sheet, Moody's does consider the impact of their inclusion on adjusted debt ratio. However, we do recognize that their inclusion does understate the company's degree of financial flexibility for meeting financial debt obligations given the long duration of those provisions. This

6. *For further discussion of the methodology of rating lease obligations see "Off-Balance Sheet Leases: Capitalization and Ratings Implications – Out of Sight But Not Out of Mind", October 1999.*

is because the cash outflows for these liabilities will not occur for a number of years and will then extend out in a form similar to operating expenses over a further extended period of time. This is taken into account by looking at both gross and net debt ratios.

U.S. Securitization

Beginning in the late 1990s, legislatively approved stranded cost securitization has become an increasingly used financing technique among investor-owned electric utilities. In its simplest form, a stranded cost securitization isolates a dedicated stream of cash flow into a separate special purpose entity (SPE) and uses that stream of cash flow to provide annual debt service for the securitized debt instrument.

Moody's generally treats securitization debt of industrial and financial issuers as being on-credit debt. The debt that is being securitized usually carries a rating that is higher than that of the issuing entity, and the assets that are being sold to the separate SPE are often of better quality than the assets that remain with the issuer.

Stranded cost securitization differs somewhat from other generic securitizations because the asset being sold is often of poor quality prior to the passage of legislation and the completion of a securitization. In most cases, the asset represents stranded costs that would have been written off by the utility in the absence of legislation allowing for recovery through a surcharge on regulated customers.

Instead, the state regulator – and sometimes the state legislature – establishes the authority for a surcharge on customers' bills, and authorizes the sale of securitized debt. The utility then sells the right to collect a dedicated stream of future cash flows from its regulated customer base that is sufficient to provide debt service on the securitized piece of debt. The issuing utility is typically required to use the proceeds of the debt offering to retire both debt and equity in a manner intended to maintain a predetermined capital structure. The securitization generally has language that enables the tariff to be unilaterally raised in the event that future sales turn out to be lower than originally planned.

Generally speaking, Moody's views stranded cost securitization as being credit-neutral to credit-positive since it typically addresses a major credit overhang, some form of potential stranded costs, and legislatively requires the utilities to use the proceeds for debt and equity reduction in a manner that targets a relatively conservative capital structure.

For the most part, the securitization tariff is separate from the "general tariff" charged to customers and any increase in the size of the securitization tariff is not at the expense of the general tariff. However, in two states, Illinois and Michigan, the utilities operate under a rate freeze, which precludes them from raising rates until the termination of their respective rate freeze. As such, any increase in the securitization tariff is at the expense of revenues and cash flow that would be available to service debt of the remaining creditors of the utility.

Along the same lines, Moody's notes that the size of the securitization tariff relative to the total tariff is an important element in evaluating the credit implications of a securitization because it can impact the future ability of a utility to obtain subsequent rate relief for other costs of service. In effect, customers do not discriminate between the securitization tariff and the general tariff when paying their bills. Consequently, to the extent that the securitization tariff needs to be increased, the financial flexibility and associated credit quality of the utility may be compromised, particularly if the securitization tariff is large relative to the general tariff and if the increase is taken from the cash flow of the utility. As a consequence, Moody's considers the impact that a securitization may have on the ability of the utility to raise rates in the future.

In calculating balance sheet leverage, Moody's treats the securitized bonds as being fully non-recourse to the utility even though accounting guidelines require the debt to appear on the utility's balance sheet. Consistent with this view, all balance sheet capitalization metrics exclude the securitized debt from the capital structure given the legal separateness that exists between the debt of the utility and the debt of the SPE, and the fact that regulators set future rates based upon a capital structure that does not include the securitization debt.

However, in looking at cash flow coverages, Moody's analysis stresses ratios that include the securitized debt in the company's total debt as being the most consistent with the analysis of comparable companies. This recognizes that regulatory approval for recovery of stranded costs and securitization are not always inextricably linked. Many utilities have approval for recovery of stranded costs but do not execute a securitization financing. Regulatory approval of stranded costs can be a credit transforming event when there is substantial doubt about recovery. However, the subsequent completion of a securitization financing does not change the amounts that are expected to be recovered. A securitization transaction does make it extremely unlikely that regulators can later disavow an agreement to allow recovery, and regulatory approval is often packaged together with a securitization with the view that ratepayers will benefit from low borrowing costs.

While our standard credit ratios for funds from operations to total debt and funds from operations interest coverage include the securitization debt, Moody's also looks at these two metrics without the securitization debt, to ensure that the benefits of securitization are not ignored. In making this adjustment, funds from operations is adjusted downward by the amount of principal amortization that is annually paid to the SPE in support of the securitization. Consistent with that adjustment, Moody's excludes the principal amount of securitization debt in the denominator in calculating a company's Adjusted FFO/Adjusted Total Debt and excludes the portion of a company's interest costs relating to the securitized debt when calculating a company's Adjusted FFO/Adjusted Interest. The analytical benefit of making this adjustment helps to determine the amount of residual cash flow (cash flow after satisfying securitization debt service) that is available to service the debt of general creditors.

The recent bankruptcy of Pacific Gas and Electric Company (PG&E) fortifies the strength of the legal separation among cash flows available to the SPE and cash flows available to the utility. Throughout the bankruptcy, funds dedicated to the securitization debt were collected by the utility and transferred on a daily basis to the trustee for the SPE creditors and PG&E's general creditors and the bankruptcy judge never challenged the continued transfer of such funds to the SPE. For this reason, the securitization debt of PG&E remained rated Aaa while the company operated in bankruptcy for more than three years.

ADDITIONAL RISK CONSIDERATIONS

Analysis of Multiple Legal Entities within a Single Issuer Family

Utility companies may have multiple legal entities within a single consolidated organization. This is the prevalent legal structure in the US, even for small utilities. The multiple-entity legal structure is also common in Canada and the UK and is employed by a number of the larger international utilities in other countries. In the US, most utility families have an unregulated holding company. The holding company will have one or more regulated operating subsidiaries, and may have one or more unregulated subsidiaries. Most utility families in the US issue debt at multiple legal entities within the organizational family.

In the case of multiple legal entities within a single issuer family, our approach is to assess each issuer on a stand-alone basis as well as evaluating the creditworthiness of the consolidated entity. We then assess the degree of legal and regulatory insulation that exists between the lower-risk regulated entities and the higher-risk unregulated entities.

The degree of notching (i.e. the rating differential) between entities in a single family of companies depends upon the degree of insulation that exists between regulated and unregulated entities. If the regulatory framework or regulatory practice establishes that there is substantial ring-fencing type insulation for the regulated entity, there may be three or more notches of rating differential between the regulated and the unregulated entities. If there is little or no ring-fencing, there will usually be only a one- or two-notch differential between the unregulated entity (in most cases a holding company) and the regulated entity (in most cases an operating company).

Regulatory ring-fencing for utilities may include minimum equity requirements, limitations on the movement of funds from regulated entities to unregulated entities, and prohibitions against credit support by regulated entities for unregulated entities. This may exist by statute, but most typically takes the form of rules that are established by the regulator. In the United States, where these provisions are most common, the rules may differ for individual utilities in the same state.

Many regulators restrict the ability of utilities to extend intercompany loans, guarantees, or to make payments to unregulated affiliates and parent holding companies. For example, utilities in the state of Wisconsin may only pay dividends to their unregulated holding company (the ultimate parent company in these organizations) in excess of an amount established in each rate case if common equity falls below an authorized level.

Regulators also often have wide discretion to impose new restrictions on regulated entities when the utility appears to be threatened by weakness of its unregulated affiliates. For example, the state regulatory commission in Oregon established tight limitations on any movement of funds by Portland General to its parent company when the parent company filed for bankruptcy protection. These ring-fencing protections were a key reason that Portland General did not default or experience substantial financial distress while its parent was in bankruptcy.

Where regulated utility entities are not well insulated from unregulated affiliates, the ratings of these entities will be notched fairly closely, generally within one or two notches. This will be the case even when one entity has substantially stronger financial ratios than its affiliate, if there is little or no restriction upon movement of funds between the two entities, or if there is a substantial operational interdependence. For example, where the regulated utility is highly dependent upon contractual purchases of power from its unregulated generating affiliate, the ratings of these two entities will likely be one or two notches apart even if their individual financial profiles would suggest different ratings on a stand-alone basis.

Where regulated utility entities are strongly insulated from unregulated affiliates through prohibitions on loans and credit support, where there are strong regulatory limitations on dividends, and where there is little or no operational interrelationship between regulated and unregulated affiliates, the ratings will be driven more by the stand-alone credit quality of each entity, and may be three or more notches apart.

Non-specific utility risk factors

The majority of the risks considered in this rating methodology are specific to utilities. However, lenders to utilities are also exposed to many of the risks that are common to all industrial companies. These are not covered in detail here as a full analysis can be found in the relevant Moody's research. However, it should be noted that such factors may potentially outweigh the utility-specific considerations covered in depth in this report.

For example, a company that currently shows very strong financial ratios and operates in a supportive regulatory framework could still have a relatively low rating if it had very weak liquidity arrangements or high "event risk" such as if it were pursuing an acquisition policy that was very likely to result in a change in the company's business risk policy going forward.

The generic industrial company risks to which a utility may also be exposed include the following:[7]

- An assessment of the adequacy of the company's liquidity arrangements[8]
- An assessment of the quality of its corporate governance arrangements[9]
- An assessment of the quality of its management – their experience, appetite for risk and ability to fulfill the company's stated strategy
- An assessment of event risk and the probability that this could lead to a change in the company's financial position, business risk profile or its regulatory and political operating environment[10]
- Exposure to off-balance sheet risks[11]
- The potential support of or interference by a sovereign or sub-sovereign entity[12]

Regional Considerations

RATING DIVERGENCE LIMITED AMONG JAPANESE UTILITIES

Japanese electric utilities are rated in a relatively narrow range from Aa3 to A1. This reflects Moody's view that the conservative and predictable regulatory regime, and the individual companies' solidly established franchises in their operating regions, will not lead to major differences in credit risks among the rated utilities. Their financial profiles are more or less comparable, and they have simple corporate structures and limited business diversification exposures.

Moody's rates the three utilities that cover Japan's three largest economic areas at Aa3 (Chubu Electric Power, Kansai Electric Power, and Tokyo Electric Power), and six other utilities at A1 (Chugoku Electric Power, Hokkaido Electric Power, Hokuriku Electric Power, Kyushu Electric Power, Shikoku Electric Power, and Tohoku Electric Power).

Japan's regulator makes the maintenance of supply security its primary policy objective, followed in priority by environmental protection and, finally, allowing market mechanisms to work. This approach preserves utilities' integrated operations and makes them responsible for final supply to users in the liberalized market.

The government is gradually deregulating the industry and expanding the liberalized market. This market, which was partially introduced in 2000, was expanded from about 26% of the total to about 40% in April 2004, and will be

7. See, for example, "Industrial Company Rating Methodology", July 1998
8. See, for example, "Moody's Liquidity Risk Assessments – Q&A", March 2002, "Moody's Analysis of US Corporate Rating Triggers Heightens the Need for Increased Disclosure" and "Rating Triggers in Europe: Limited Awareness but Widely Used Among Corporate Issuers", September 2002
9. See, for example, "U.S. and Canadian Corporate Governance Assessment", August 2003 and "Moody's Findings on Corporate Governance in the United States and Canada: August 2003 - September 2004", October 2004
10. See, for example, "Event Risk's Four Horsemen of the Apocalypse: Decapitalization, Cash-financed M&A, Litigation, and Accounting Irregularities", November 2000 and "Event Risk For European Corporates 2003 – Still A Credit Risk, Still Part Of Our Analysis", February 2003
11. See, for example, "The Analysis Of Off-Balance Sheet Exposures: a Global Perspective", July 2004
12. Note: Moody's paper "The Incorporation of Joint-Default Analysis into Moody's Corporate, Financial and Government Rating Methodologies" February 2005 which may effect the ratings of, for example, a municipality supported by a regional or national government.

further expanded to about 63% in April 2005. However, the pace of deregulation has been set as moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of supply security.

The Japanese utilities hold strongly established franchises in their operating regions, maintaining dominant market shares despite the market for large customers being deregulated. Some utilities still hold 100% shares.

Direct competition among integrated utilities has been very limited. This is mainly because: (1) each integrated operator holds a solid franchise in its operating region due to effective regional monopolies; (2) the companies display similar cost positions, and achievement of any meaningful differentiation in pricing is difficult; (3) the utilities are fully aware that an aggressive challenge by one utility in another's franchise would trigger industry-wide competition, which would, in turn, significantly weaken the industry's overall profitability; and (4) all the utilities exhibit similarly leveraged balance sheet positions and place priority on debt reduction, having completed most of their major investments.

In addition, the ability of power producers and suppliers (PPSs) to take utilities' shares has been restrained by limitations on: (1) their ability to purchase power from, for example, captive power plants; (2) their opportunities to build competitive plants on their own; and (3) their marketing abilities.

Although PPSs have been gaining minor shares in some utilities' franchise areas, and some are constructing their own power plants, their aggregate share is expected to remain insignificant over the intermediate term, due to power companies' rate strategies aimed at protecting their franchises and PPSs' ongoing limited access to power sources.

As such, although the rates are to be further lowered through the ongoing deregulation process, we expect the utilities' franchises to remain solid and stable over the intermediate term.

Government energy policy has made nuclear generation a core power source, while leaving actual implementation of the policy – construction and operation of nuclear power plants – to privately owned and managed utilities. Thus, these companies play an important role in the nation's energy policy, although the government remains the main driver by establishing and maintaining their nuclear power operation systems.

The government is now reviewing the economic feasibility of the nuclear fuel cycle, the allocation of back-end costs, and power utilities' reserves for back-end costs. While the outcome of the review could affect utilities' investment, cost, and balance sheet positions to some extent, we do not expect any significant changes in their policy role, business risks or cost competitiveness.

EUROPE

EU policy is the driver for regulatory development in Europe

The EU Electricity Directive of 1999, subsequently amended by the EU Energy Council in 2002, set the roadmap towards full supply liberalization in the European Union as well as addressing issues such as non-discriminatory access to the transmission grid and the granting of new generation licenses. The current aim is to have full liberalization within the EU by 2007.

Despite EU policy, there is a regulatory patchwork across Europe

Despite the EU directive, there is some flexibility in its implementation, leading to different regulatory models. The process has in most cases led to the establishment of an independent regulator, although the degree of independence from government influence varies significantly. In some countries, such as Spain and Greece, the government maintains control for final setting of tariffs and the regulator acts in an advisory capacity, whilst at the other end of the spectrum are those countries where there is a fully independent regulator, such as in the UK.

Having achieved full supply liberalization, the regulator can focus on regulating the monopoly wires activities – transmission and distribution. The UK has adopted an ex-ante approach, with a tight regulatory framework for wires activities. "Ex-ante" means setting the tariffs in advance, normally for a 3-5 year period, and the regulator allows the company to recover operating and capital expenditures as well as a return on capital. Normally the regulator will benchmark companies against their peers and will allow certain revenues (a revenue or price cap), often adjusted for inflation and an efficiency incentive, depending on how efficient the company is perceived to be.

By contrast, Sweden and Finland initially adopted a much lighter "ex-post" system, which allows companies to set their own prices to achieve a reasonable return on a cost-plus basis, with an arbitration mechanism to allow for complaints and remedies. Despite this looser regime, prices in these markets have been some of the lowest in Europe, benefiting no doubt from the overall greater price transparency from a fully liberalized market. However, under further direction from the EU, Finland and Sweden (and Denmark) are now moving towards an ex-ante regime and this we would expect to become the norm in Europe.

Germany has yet to establish an independent regulator – although it is now moving in this direction – with network tariffs being set within the context of a voluntary agreement between utilities. Access tariffs are set on a negotiated basis, but in practice the German market is difficult and expensive for new entrants to access.

In Moody's view, power shortages in 2003 have led to an easing in regulatory pressure as security of supply displaces cost as a key aim

Regulators initially introduced quite harsh efficiency incentives or tariff caps, with tariffs reduced in real terms as companies have become more efficient. However, recent tariff pressure has been upward, e.g. Spanish tariffs fell in real terms between 1996 and 2002 but the current tariff framework now allows for gradual increases. This can be explained by greater concern over security of supply, with Europe having experiencing blackouts during 2003. Moody's believes that regulators wish to ensure that an incentive to invest remains, particularly as some aged thermo capacity and a number of nuclear plants are earmarked for decommissioning in the next few years.

In Central and Eastern European countries, regulation is following in a similar direction but at a slower pace

Central and Eastern European countries and the Baltic states are following EU directives, but are at an earlier stage of regulatory evolution. Whilst most have put in place at least the first Energy Law, implementation is often at an early stage under an extended implementation timetable or relatively new and untested. Many of these countries have now established an independent regulator although there is still a state-owned incumbent with a dominant or monopoly position.

These countries typically face privatization, structural separation (generation, transmission, distribution and supply), tariff increases and issues concerning cross-subsidization – with accession states such as Romania and Bulgaria aiming to have completed the process by 2007. Electricity market development is often linked to the economic and structural development of the country in which they operate. Indeed, the requirements of the IMF or World Bank may allow for only a gradual increase in tariffs (Romania and Bulgaria).

From a credit perspective, whilst the timely recovery of all costs may be delayed or constrained, the impact of such can be mitigated by the dominant market position of these key utilities and/or their strategic importance to the State and the role they play in the development of the economy.

Rating the UK regulated transmission and distribution companies

The UK electricity system is divided into a number of monopoly areas for the high-voltage transmission and lower-voltage local distribution of electricity. There is one monopoly transmission area and 12 Distribution Network Operators (DNOs) covering England and Wales. Two additional companies have the monopoly rights to transmission and distribution in distinct areas within Scotland. As these businesses are monopolies they are subject to price control regulation primarily aimed at protecting the consumer's interests.

All of these businesses are regulated by the Office of Gas and Electricity Markets (OFGEM). OFGEM itself is an independent body governed by an authority made up of independent, non-executive Directors and an Executive team. OFGEM is not part of the UK government but its duties and powers were established by Acts of Parliament and they must have regard to guidance from the government on issues such as protecting the environment.

The revenue that a monopoly business can earn on its regulated business is restricted by an RPI-X price control formula that is reviewed every five years. The formula is designed to allow a company to increase prices to reflect inflation while encouraging efficiency through a "-X" from the RPI. In addition, at the start of each regulatory period, prices are raised or reduced by a one-off price adjustment known as the P_0 adjustment. In order to calculate the "X" and the "P_0" for each company, OFGEM considers the Regulatory Asset Base of each company and sets a formula to provide a fair rate of return on those assets, typically around 6-7%. The next regulatory period for the transmission companies starts in 2007 and for distribution companies in 2005.

The practical regulation system involves a very detailed analysis of each company's regulated asset base and operating and capital expenditures. The output is a very detailed and highly predictable cashflow forecast for the next regulatory period. If the companies can improve efficiency, then they can retain most of the benefit. However, if they lose efficiency or the regulatory outcome proves unachievable, then this is a risk for the stakeholders in that company.

For Moody's, the ratings of these businesses depend upon two key factors:

1. The projected financial position of the company once the final regulatory outcome is known. This is measured by a number of financial ratios including FFO interest cover and Debt/Regulated Asset Value.
2. The additional burdens placed on the regulated entity's cash flows by its parent, mainly in the form of additional parental debt which needs to be serviced by dividends from the regulated operating company.
3. DNO-specific issues such as unfunded pension deficits unrelated to the distribution business, debt maturity profile and debt capital structure considerations.

According to OFGEM, after these adjustments, the intention is that all companies will earn the same baselines return of 6.6% on a pre-tax, real basis if they perform in line with the regulator's projections. The main issues are expected to be the need to increase capex to replace network assets and improve network performance, to put a greater emphasis on quality of service, and to respond to the growth in sources of renewable energy. These final determinations for the 2005-2010 price control period will become effective in April 2005.

The main rating implication from these proposals is likely to fall on companies whose overall financial profile is burdened by the need to pay large dividends to service and repay debt at holding company levels. While this can lead to a significant cash drain, the debt at the holding companies is outside the regulatory ringfence and is not protected by the OFGEM framework. One such holding company, Avon Energy Partners, has already defaulted on its debt obligations, while the operating company Midlands Electricity had no financial difficulties, thus illustrating that lending to such holding companies is significantly more risky than lending to the regulated entity itself.

When looking at the financial ratios for regulated UK DNOs, there are a number of important considerations to bear in mind:

1. The Regulated Asset Value (RAV) is an important reference point as allowable revenues and allowable capital expenditures both feed from or into this. Hence, the Debt/RAV ratio is one of the more critical financial ratios to consider.
2. OFGEM's scope of regulation is limited to the regulated entity, while Moody's rating of the DNO also factors in debt which must be serviced by cash flows from the DNO. This means that an RCF number (cashflow after dividends) is an important one for a DNO. It also means that ratios factoring in any "Holdco" debt tend to outweigh pure "stand-alone" DNO ratios. In practice, there are no remaining stand-alone DNOs.
3. Some DNOs retain cash to meet future debt maturities and where this is the case, the emphasis falls on net rather than gross debt numbers.

As a guideline and ignoring other considerations, the following ratios might be expected for UK DNOs at various rating levels, without factoring the need to support other group debt (if there is such debt, stronger ratios would be needed for the same rating level):

Figure 6

DNO	RCF/Net debt	Net debt/RAV	FFO interest cover
Aa	> 17%	< 45%	> 4.5 X
A	7 – 18%	40 – 60%	2.8 – 5.0X

AUSTRALIAN T&D RATINGS ARE HIGHER THAN UK RATINGS FOR COMPARABLE ENTITIES

Differences in regulatory philosophy between Australia and the UK mean that Moody's on average rates Australian electricity transmission and distribution (T&D) companies one notch above the ratings of their UK peers, even though both parties may have approximately the same level of debt coverage measures.

Furthermore, the impact of the regulatory differences is such that when Australian and UK companies share the same rating level, the Australian companies conversely exhibit weaker debt coverage measures. Moody's believes that the financial profiles of Australian T&D companies are sustainable within their present ratings, given their benign regulatory environments.