



Electricity Restructuring in the USA and its Effects on the Nuclear Industry

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In recent years and with an accelerating pace, the United States has been restructuring its electrical power markets. At the national level, reform has concentrated on transforming the regulated wholesale market for electricity into a competitive market. At the state level, emphasis has been placed on providing a competitive retail market. Ultimately, individual households in the United States will be able to choose their energy provider in much the same way that they now choose their long-distance telephone carrier. These changes will have profound effects for the electricity utility industry — particularly nuclear operations.

This paper addresses the current state of electricity utility deregulation in the United States and some of the major issues presently facing regulators, legislators, the electricity utility industry, and the nuclear industry. While the author has endeavoured to provide the most accurate analysis possible, the pace of reform in some jurisdictions will no doubt quickly render some of the information obsolete.

Restructuring at Federal and State Levels

FERC Order 888: Federal Restructuring Blueprint

The electricity industry restructuring bandwagon has gained momentum from recent deregulatory efforts successfully undertaken in other US industries. In 1992, for example, the Federal Energy Regulatory Commission (FERC) acted to infuse competition into the natural gas industry through a pair of sweeping orders. FERC found that natural gas transporters were offering bundled sales services rather than non-discriminatory trans-mission access. Within a few years FERC and others noted that

the electricity utility industry was also ripe for the beneficial infusion of competition given the substantial technological advancements and growth of the industry. Beginning in 1993–94, FERC turned its attention to this issue.

However, as explained below, FERC's approach to electricity utility restructuring differs greatly from the approach it used to deregulate the natural gas industry. For example, FERC required an equitable sharing of take-or-pay costs between shareholders and customers in natural gas restructuring, but allows full recovery of stranded costs for electricity utilities. In addition, while gas take-or-pay costs were borne broadly by all natural gas consumers, FERC has mandated that stranded costs be recovered through exit fees charged to departing customers.

FERC has thus far taken the leading role in restructuring the wholesale energy market in the United States. (FERC's jurisdiction is limited to the wholesale market for electricity in interstate commerce; it lacks jurisdiction over the sale of electricity at retail level, which is the domain of the various state public utility commissions.) In the Energy Policy Act of 1992, the US Congress granted FERC additional powers to require electricity utilities to provide access to their transmission grids to potential competitors for the sale of electricity in wholesale markets. FERC, relying on these new powers, instituted a rulemaking to mandate "open access" to transmission services. Its plan is set forth in the mammoth-sized Order 888 which was finalised on 24 April 1996.

Order 888 requires that all public utilities in the

United States comply with regulations intended to further the Energy Policy Act's primary goals. First, Order 888 seeks to ensure "comparability" among public utilities. By this, it is meant that each utility must file open access transmission tariffs offering both network and point-to-point services on a basis comparable to that which it provides transmission service for itself on behalf of its own customers. This standard pro forma tariff will apply to all wholesale utilities (including the transmission provider itself), some retail customers, and any foreign entities that meet an independent reciprocity requirement. These tariffs went into effect at the beginning of 1997. To date, the application of the pro forma tariff has been strictly enforced by FERC. Very few modifications to submitted tariffs requested by transmission providers have been allowed.¹

Besides the open access tariffs, FERC has required other changes to be made by transmission providers to ensure a level playing field. For example, all transmission providers must maintain certain ancillary services for utilities. Ancillary services have been defined by FERC as: "those services which are necessary to support the transmission of electrical power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."² These services include scheduling, system control, dispatch, voltage control and operating reserve services. The cost to the customer utility choosing to partake of these services is set by the pro forma tariff.

In addition, FERC sought to ensure that utilities subject to its jurisdiction and to the requirements of Order 888 could effectively compete with utilities that are not under the agency's jurisdiction, eg. utilities that do not transmit electricity in interstate commerce, municipally-owned utilities, and electricity cooperatives. Therefore, the order contains a "reciprocity requirement". Any pro forma tariff customer must agree to provide, as a condition to buying transmission services under the tariff, comparable transmission services to the transmission provider on similar terms and conditions over its transmission facilities and the transmission facilities of its corporate affiliates. To qualify, a utility not subject to FERC's jurisdiction must seek a declaratory order indicating compliance with the reciprocity requirement or obtain a waiver from FERC of the reciprocity requirement.

Besides comparability, Order 888's second stated goal is the "functional unbundling" of the generation

and transmission activities of utilities. By separating these operations both physically and organisationally, FERC's objective is for the transmission of electricity to be conducted without favouritism to the particular controlling utility. FERC did not believe that corporate unbundling (requiring the actual selling of the transmission facilities or the creation of a separate corporate subsidiary) was necessary to ensure fair competition.³ Instead, FERC chose a functional separation. This approach is effected by three different policies implemented through Order 888 and through a sister order promulgated on the same day, Order 889.

First, FERC adopted a code of conduct in Order 889 to govern the mechanics of functional unbundling. These rules are designed to ensure that the utility's employees engaged in transmission operations are insulated from contact with employees engaged in wholesale purchases and sales of electricity. Thus, salesmen and purchasers are not to be allowed into the transmission control room and they cannot be given preferred access to transmission information. Any violations of the code of conduct have to be reported immediately.

Second, FERC recommended, but did not mandate, the creation of an independent system operator (ISO) to manage the transmission system of a utility or group of utilities. An ISO would have the primary responsibility of ensuring the short-term reliability of the grid and would be unaffiliated with any particular utility. Thus, several local transmission providers could relinquish control over the grid to an unbiased, competent professional organisation that would ensure fairness in the transmission process. In a similar development, FERC has shown a substantial willingness to embrace power pools and regional associations based on open transmission access.

Third, FERC has created an Open Access Same-Time Information System (dubbed OASIS) by virtue of Order 889. This Internet-based system is to be used by all transmission providers in the United States as a near-instantaneous transmission reservation system. Thus, competing wholesale utilities (including the transmission provider's own generation operations) will have the ability to see transmission availability and costs at the same time. By putting this information on-line and allowing instantaneous reservations, FERC hopes to minimise any favouritism given to the transmission provider's affiliated entities.⁴

As could be expected, the changes resulting from the Energy Policy Act's implementation by FERC are welcomed by some utilities and feared

by others. Some utilities in the latter group are concerned that much of the large capital expenditures they made in reliance on the old regulatory scheme for plant and equipment will be unrecoverable under a competitive-rate system. Recognising both the potential unfairness of the change to a competitive market and the possibility that some utilities with substantial, unrecovered sunk costs may not be able to compete without some initial assistance, FERC has agreed that it is critical that utilities should be able to recover their stranded costs.⁵

These costs are defined as the difference between what a utility must be able to charge to cover its operational and investment costs and the price it would be able to obtain in a deregulated environment. According to a 1995 report conducted by Moody's Investor Services, 57 of 114 utilities examined by Moody's have enough debt to place them at significant risk in a deregulated electricity market. The size of the stranded debt pool has been estimated by Moody's to be US\$136 billion — a figure larger than the size of the crises in the Savings and Loan institutions in the United States in the late 1980s. Under Order 888, stranded costs that are proven "legitimate, prudent, and verifiable" will be assigned to departing wholesale generation customers either as an exit fee or as a surcharge on transmission. Transmission providers must also show that they had a reasonable expectation of continuing to serve the departing customer.

FERC's position on stranded costs is extremely important for utilities with substantial, unrecovered sunk costs — which includes many nuclear utilities — for it implicitly recognises the reliance that the industry placed on the previous rate-regulated system and the reasonableness of that reliance. However, the standard employed by FERC for the recovery of stranded costs — "legitimate, prudent, and verifiable" — is vague. While many energy lawyers in the United States surely revel in the ambiguities of words such as "legitimate" and "reasonable", some experts fear protracted litigation over these malleable standards. Indeed, public interest groups across the political spectrum have announced the formation of a new coalition opposing stranded cost recovery. Thus, the ultimate effect of FERC's stranded cost provisions is as yet unclear.

The resolution of the stranded cost issue is not only the concern of the electricity utility industry and consumer groups. If a surcharge method of recovery is endorsed at the national level (as it has been for local services in certain states), an

opportunity would be created to "securitise" much of the stranded costs associated with utilities. This process could result in the creation of over US\$75 billion in utility bonds backed by a steady revenue stream from consumers paying utility bills. Bond market investors have thus become very interested in the emerging restructuring plans.⁶

Institutional shareholders are likewise keenly interested in restructuring's ultimate shape. Under the regulated regime, with its assured rates, utility securities are considered fairly safe investments. After competition takes hold, however, many investors will be faced with a more risky proposition. Pointing to some incidents at the state level, some experts fear that radical restructuring without recovery of stranded costs could lead to a collapse of these investments.⁷ Thus, restructuring poses both promise and problems for Wall Street.

In addition, common wisdom holds that changes in the electricity utility industry will result in many new corporate recombinations and mergers as utilities seek to disaggregate unprofitable divisions. FERC has adopted a new policy statement that refines its merger review criteria and procedures. FERC has traditionally applied a six-factor balancing test to determine if a proposed utility merger is consistent with the statutory requirement — that is, whether it would be "consistent with the public interest". The new policy limits these factors to three: the effect of the proposed merger on competition, the effect on rates, and the effect on regulation.

Regarding the first criteria (the effect on competition), FERC has agreed to abide by the United States Department of Justice/Federal Trade Commission Merger Guidelines. These guidelines have been used by these other agencies to evaluate possible violations of antitrust laws and are already familiar to many American businesses.

The second factor (the effect on rates) is fairly straight forward. The ultimate purpose of deregulation and competition is to lessen the cost to consumers of the power they use. FERC will review any proposed merger in order to ensure that the lower rates expected from competition will not be endangered by new corporate combinations.

The last factor (the effect on regulation) ensures that mergers will not result in an operating public utility escaping FERC's jurisdiction by virtue of its new corporate form. FERC hopes that by clarifying and limiting its review of corporate combinations, it can streamline the merger application process and process such requests

within 12 to 15 months. The policy statement will be codified in a future rulemaking proceeding.

Congressional Action

FERC is not alone in its concern over the restructuring of the electricity utility industry. While the Congress has not yet passed a comprehensive energy reform package, momentum is growing and some sort of action is quite possible, although it is unclear how soon it will occur. While many such bills have been introduced over the past few years, four widely commented upon proposals demonstrate the substantial divergence of views that pervade the congressional debate. In essence, there is a tension between whether implementation of a deregulated electricity market falls within the purview of the federal government or whether it should be left to the individual states.

First, Senator D'Amato of New York has proposed that reform initially be limited to repealing major federal legislation that restricts competition. In particular, his bill, S621, would repeal the Public Utility Holding Company Act (PUHCA). PUHCA creates a dichotomy of regulatory jurisdiction: the SEC currently regulates the 15 registered utility holding companies, but FERC regulates their electricity utility and gas pipeline subsidiaries.

Enacted in 1935, PUHCA limits the ability of electricity producers to purchase other producers. Senator D'Amato's bill has been through the Senate Banking Committee's mark-up process, and seems to have enough support for passage in the Senate, even according to opponents.⁸ However, consideration of the bill by the full Senate has been delayed because of a procedural hold placed on the bill by Senator Dale Bumpers of Arkansas, an opponent of the measure, who believes that such reforms should be part of more comprehensive restructuring legislation.

Second, Representative Markey of Massachusetts has proposed potentially more sweeping reforms. His bill, HR1960, contains a presumption in favour of retail competition at the state level, but would allow states to opt out if they chose to do so. Utilities in states that refused to deregulate would still have to comply with PUHCA. However, all other utilities would be exempt from PUHCA. While the Congressman personally opposes the recovery of stranded costs, under his proposed legislation any stranded cost recovery would be up to the individual states.

Third, Representative DeLay of Texas has authored bill HR1230 that is far more aggressive

in its promotion of competition. Under his plan, all states would be required to implement competitive retail systems by 1 January 1999, and it would flatly prohibit the imposition of transitional charges to recover stranded costs. This approach and the refusal to allow recovery of stranded costs is necessary, according to Congressman DeLay, "to protect families and small businesses from becoming the economic scapegoats for billions of dollars in questionable investment decisions".

Fourth, Representative Schaefer of Colorado, Chairman of the House of Representatives Commerce Committee's Subcommittee on Energy and Power, has introduced HR655. Under his plan, all states would be required to implement consumer choice and retail wheeling plans by 15 December 2000, but the individual states would retain the authority to establish the details for implementing competition at the retail level, including whether stranded costs may be recovered.⁹

In addition, HR655 would repeal PUHCA and would also eliminate key provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA encourages the increased use of alternative energy sources. Many utilities consider PURPA's alternative energy requirement to be a form of stranded cost and thus advocate its repeal.

Representative Schaefer's plan has received the most attention in Congress as the most likely vehicle for federal restructuring legislation. The Commerce Committee and Congressman Schaefer's subcommittee have held hearings and town meeting-style discussions within the past few months on many issues related to utility restructuring, including grid reliability, quality of service concerns, and affordability.

President Clinton's administration is working to present a consensus proposal drafted with the help of most of the concerned executive agencies. The Department of Energy is the lead agency developing the proposal. Energy Secretary Federico Peña has indicated in public appearances that the administration's proposal will include support and incentives for greater use of renewable energy sources and possibly stricter clean air protection.¹⁰

The US electricity industry is generally opposed to additional environmental regulation being included as an add-on to any restructuring legislation. Peña has also indicated that the Administration's plan would include some flexibility for state involvement. Deputy Energy Secretary Elizabeth Moler indicated recently that the administration's position on electricity utility

restructuring will be developed by the third quarter of 1997. She declined to state, however, whether this will be in the form of legislation, a report, or some other form.

The debate over the exact contours of federal restructuring legislation will almost certainly be heated. Lobbying on the issue has already become fierce with millions of dollars spent on campaign contributions and hearings.

State Action at the Retail Level

The general status of the ongoing restructuring and competition reforms at the state level can be found in a study performed by the National Regulatory Research Institute dated 30 April 1997.¹¹ Every state, save one, has at least engaged in discussions over competitive restructuring. Over half have at least conducted legislative studies of the possibility. Almost a dozen have created pilot programmes to further test competitive regimes. I will discuss below the status of some of the more significant efforts undertaken to date by a few states.

California. With some of the highest electricity rates in the country,¹² California leads the deregulatory charge at the retail level in the United States. The state's US\$21 billion electricity market is perhaps the largest in the country. Legislation passed in 1996 will allow customers to begin choosing their electricity provider on 1 January 1998. The California system contains many of the features found in FERC Order 888 and the congressional initiatives described above.

For example, utilities will turn over operation of transmission facilities to an independent system operator, thus further unbundling their generation and transmission operations. A power pool will be created during a transition period. Over US\$26 billion of stranded costs can be recovered through surcharges passed on to consumers. Securitisation mechanisms have been authorised for this recovery. California estimates a 20% reduction in utility rates by 2002 as a result of introducing competition at the retail level.

Maine. In 1995, Maine's legislature ordered the state's Public Utilities Commission (PUC) to investigate the feasibility and desirability of retail electricity competition. On 31 December 1996 the PUC submitted a recommendation for such a system for the legislature's consideration. Under the PUC's recommendation, consumer choice would be implemented by 2000. As part of the restructuring,

the PUC recommended that two utilities go further than simple functional un-bundling. Rather, these utilities would have to divest themselves of generation assets by 2006. Stranded cost recovery is permissible under the proposed system.

Other proposals from some lawmakers contained widely differing requirements. In May 1997 Maine passed restructuring legislation that, by 1 March 2000, will both open up the state to full retail competition and require Maine's two largest utilities, Central Maine Power and Bangor Hydro, to divest their generating assets. However, Central Maine Power's 38% interest in the Maine Yankee nuclear power plant does not come under the divestiture requirement until 2009, one year after the plant's current licence period expires. The plan also requires that at least 30% of the electricity bought by the two utilities for resale be generated by renewable sources, and further limits the two utilities to no more than one-third of the available customers in their own distribution areas. The law does allow the recovery of stranded costs, with the details to be worked out next year.

New Hampshire. In 1996 the New Hampshire legislature enacted legislation setting 1 January 1998 as the deadline for commencement of full retail competition in the state. Under the plan, utilities that wish to sell electricity to retail customers in New Hampshire must divest all of their generation and transmission assets by 1 January 2000. The transmission system will be operated and maintained by an independent system operator. In 1997 the New Hampshire PUC issued a final order on restructuring that addressed, *inter alia*, the issue of stranded cost recovery. The order allows some stranded cost recovery, but severely limits recovery for utilities whose costs exceed the New England regional average cost of electricity.

If implemented, this stranded cost recovery limitation mechanism would force Public Service of New Hampshire (PSNH), the principal owner of the Seabrook nuclear power plant, to write off up to US\$800 million in unrecovered costs. PSNH, the state's largest electricity utility, has filed a lawsuit in the federal district court challenging the PUC order, and has stated that bankruptcy is inevitable if the PUC's order limiting stranded cost recovery remains unchanged.¹³ The lawsuit is currently pending before the court.

Pennsylvania. Late in 1996, the Pennsylvania legislature resoundingly passed a restructuring package. Under the legislation, since April 1997

the state's utilities have undertaken a pilot programme to test the framework of the new system. Under the enacted legislation, retail competition will be phased in from 1999 through 2000, with full retail competition by 2001. The legislation requires utilities to unbundle their transmission and generation functions, but it does allow utilities to recover their "known and measurable" stranded costs via surcharges passed on to customers.

Like California, the Pennsylvania legislation authorises the use of securitisation bonds for the recovery of stranded costs. One utility in the state, PECO Energy Co., has requested authority to issue almost US\$3.8 billion in securitisation bonds to recover stranded costs. The Pennsylvania PUC has, however, authorised PECO only to issue slightly less than US\$1.1 billion in such bonds. Recovery of the remaining US\$2.7 billion in stranded costs is to be considered as part of a separate investigation into PECO's restructuring plan. Environmental groups have protested the PUC's order authorising PECO to issue the US\$1.1 billion in securitisation bonds. PECO has settled with some — but not all — of the intervenors under which PECO would be compensated for the bulk of its claimed stranded costs but retail customers would get a 10% reduction in rates, effective September 1998.

Texas. Not all states have embraced the restructuring trend. After months of both informal and formal debate, the Texas legislature refused to vote on a deregulatory plan at the end of that body's 1997 legislative term. Despite strong support from the state's governor, opposition from rural electricity cooperatives, environmental groups and consumer organisations led to the defeat of the measure. In particular, these groups objected to several methods for the recovery of stranded costs. The Texas legislature reconvenes in January 1999, but meanwhile has authorised an interim study of the issue for future consideration.¹⁴

In sum, the deregulation and restructuring of the electricity utility industry is proceeding at an ever accelerating pace at both the federal and state levels. The changes that have occurred over the past several years were unimaginable less than a decade ago. These ongoing changes to a competitive marketplace have profound consequences for the nuclear power industry.

Restructuring's Effect on the Nuclear Industry

The key challenge facing nuclear power in the United States as the electricity utility industry

embarks on a path of restructuring and deregulation is to be competitive with other sources of electricity generation directly on cost. For existing nuclear plants, the determinative costs for whether an existing plant will continue to operate in a competitive marketplace are the plant's marginal costs of operation, ie. its operating and maintenance (O&M) costs and capitalised repair costs.

Stranded costs of plant construction are extremely important to the viability of the company and its stockholders and bondholders currently owning the plant, but stranded costs have already been spent. They are sunk costs for the purposes of determining if an existing nuclear power plant can or should continue to operate. Whether or how they are recouped should not affect the economic decision of whether a plant is economic to operate.

The good news for the nuclear industry is that O&M costs for US nuclear plants have fallen steadily over the past decade. Average O&M costs have dropped from 2.75¢/kWh in 1988, to 2.48¢/kWh in 1992, to 1.92¢/kWh in 1995, to 1.78¢/kWh in 1996, a drop of 35% over a period of only eight years. The lowest cost nuclear plant in the country, Virginia Power's Surry plant, had an O&M cost of just 1.15¢/kWh in 1996.

For comparison, the average nuclear O&M costs in 1995 of 1.92¢/kWh compares favourably with the 1995 average O&M cost for coal (which had the lowest production costs of the commonly used energy sources) of 1.88¢/kWh, a difference of only 2%. The 1995 average O&M costs for natural gas are considerably higher, at 2.68¢/kWh. (Hydropower is also inexpensive but is both geographically and seasonally limited.) Thus, existing US nuclear power plants are on average very competitive in terms of production costs for generating electricity.

The bad news for the nuclear industry is that a focus on marginal operating costs does not address the cost of constructing a new plant in a competitive market. On this front, the capital cost for a new nuclear power plant far exceeds that for a new natural gas plant. Although a new nuclear power plant may be competitive with natural gas if construction costs are capitalised and recovered over a 40-60 year time horizon, the shorter time horizons for expected return on capital in a competitive marketplace will result in new natural gas plants being built instead of new nuclear plants.

If O&M costs for natural gas were to increase significantly, this unfavourable picture may conceivably change. But with the current abundance

of existing and newly discovered natural gas reserves, such a change is not likely in the near future. Moreover, even assuming nuclear power were fully competitive with new fossil plants, other factors would inhibit the development of new nuclear capacity. These include the lack of an agreed solution for the disposal of radioactive wastes and spent nuclear fuel, concern over the lack of regulatory stability, and organised opposition at the national and local levels.

Although stranded construction costs should not affect the economic decision of whether to operate existing plants, stranded costs may well play a key role in determining who will operate existing plants, ie. the current owner or a new owner. Some stranded cost recovery plans may mandate that such generating capacity be sold off to the highest bidder (as a way to quantitatively determine actual stranded costs). Other stranded cost recovery plans may drive current owners into bankruptcy, at which time new owners would take over the asset at market price. Finally, current owners may choose to sell these assets at a fair market price in the near term, and take the cost readjustment as part of preparing for competition.

Whatever the fair market price for an existing nuclear power plant is determined to be — which is a major question yet outstanding — this cost will need to be included on an amortised basis in the price of electricity charged by the plant owner for the plant to be profitable in the new competitive environment. If the new owner has paid too much, the cycle will repeat itself. Economically, the plant should be closed only when it has no current net positive economic value, which in a competitive marketplace would be the point at which its marginal cost of generating electricity exceeds the market price for the electricity generated. Such an analysis is, of course, quite radical for companies in the electricity utility industry, which have operated as regulated monopolies for many years.

Stranded costs for decommissioning are similar to stranded capital costs in that they should not be an economic determinant of whether an existing plant continues to operate. Decommissioning costs — which are on the order of US\$400 million for current decommissioning efforts for large commercial plants — are sunk costs in that their expenditure is required by regulation once a plant has commenced operation. Their magnitude does not increase significantly with continued operation following the first several years of steady-state operations. (Once a plant has operated at a steady state for a number of years, the decommissioning

requirements for that plant are essentially the same whether the plant continues to operate or is shut down, unless the plant is shut down and decommissioning is delayed for several decades.)

The major variable in decommissioning cost and timing is the cost of low level waste (LLW) disposal; this has been increasing steadily over the past 10 years, with no clear abatement in sight. This steady cost increase conceivably could prompt a decision to shut down marginal plants early to take advantage of lower LLW disposal costs. However, if additional LLW sites are opened in the future, through state LLW compact efforts, the increased supply of disposal resources could drive disposal costs downward (which would be an incentive to delay the shutdown and decommissioning of nuclear plants).

Moreover, both the Nuclear Regulatory Commission (NRC) and state regulators have — to date — viewed stranded cost recovery for nuclear plant decommissioning to be a public health and safety imperative and an essential part of restructuring the electricity utility industry. If stranded decommissioning costs are recovered through a guaranteed mechanism, such as a charge on the use of transmission wires, they should not be a factor in determining whether an existing plant can economically continue to operate in a competitive marketplace.

Given that O&M costs will be the primary determinant of whether existing nuclear power plants in the United States will continue to operate, how do the various nuclear plants fare? As I have mentioned earlier, the average O&M costs for nuclear plants has been steadily declining, and is essentially the same as for coal-fired plants and is far superior to natural gas and oil-fired plants. However, while the average nuclear O&M cost is quite low, the cost is not low for all plants. A study published in February 1997 by the Washington International Energy Group (WIEG), sponsored by the INGAA Foundation, an arm of the natural gas pipeline industry, concluded that some 40% of the nation's nuclear generating capacity faces the risk of shutdown due to adverse economic factors in a competitive market.

The nuclear industry and others have responded that the WIEG study is too pessimistic. Attacks have been made on its assumption as to future energy prices and the trend of O&M costs, as well as on its methodology. The study's conclusion, even though criticised as overly aggressive, is a wake-up call for the US nuclear industry. While the early nuclear plant shutdowns may not be as

numerous as predicted by the study, there will be early plant closings. By early, I mean plants that are closed for economic reasons prior to the end of their current licence period.

We have already seen several plant closings occur for economic reasons. Prior to 1996, the 175 MWe Yankee Rowe and the 1130 MWe Trojan plants were shut down early in order to avoid paying for costly plant changes necessary to operate to the end of their licence terms. In the past year, other plants have joined or announced they will soon join this list. The 560 MWe Connecticut Yankee has been shut down permanently. The owners of the 870 MWe Maine Yankee and the 610 MWe Oyster Creek plants have each announced plans to shut down the plants early unless another company wants to purchase the plant and continue operation.

The owner of the tiny 67 MWe Big Rock Point plant, the oldest currently operating reactor in the country, recently announced that it will shut the plant down two years early because its cost of electricity production was too high. Most surprisingly, Commonwealth Edison, one of the largest nuclear utilities in the United States, recently announced that its twin 1040 MWe Zion units will be shut down early because it cannot justify the cost of replacing the plant's steam generators to allow the units to operate to the end of their licence period.

On the other hand, there are many nuclear plants in the country whose marginal cost of operation is near or below 2¢/kWh, which appear to be very competitive. Moreover, several licensees, such as Duke Power (Oconee) and Baltimore Gas and Electric (Calvert Cliffs), are continuing to consider licence renewal to extend the licensed operating periods of their nuclear power plants for another 20 years. Also, companies have expressed an interest in purchasing and continuing to operate the Maine Yankee and Oyster Creek plants, even though their current owners have announced plans to shut them down early.

Factors Affecting Nuclear Competitiveness

Structural Factors

Several key factors should be taken into account in determining the competitiveness of a particular nuclear power plant in the restructured marketplace. The most important structural factor is the net electrical generating capacity of the plant. A large part of the infrastructure, and therefore cost, required to operate a nuclear plant is fixed. Even a small capacity plant requires a large workforce

to operate the facility. The greater the number of megawatts generated by the plant that these costs can be spread over, the lower the effective plant generating cost per kWh.

A clear example of this is the tiny Big Rock Point plant, with an output of 67 MWe. Though the plant has always been very well operated, the cost of the large staff required to operate it simply made the unit cost of electricity too high. A related structural factor is the number of units at a site. A site with several units can spread certain site costs, such as security and engineering, over the total electricity output of all the units at the site, thus lowering the overall cost of electricity generated per kWh. This efficiency is magnified when there are identical, or very similar, units at the same site.

A related efficiency factor is the total number and type of units operated by a given licensee, which allows corporate infrastructure costs to be spread over a greater number of total megawatt-hours. While this factor appears to be significant for some licensees, other multi-unit licensees have not seen these efficiencies.

Licensees with a single, small nuclear power plant are working to offset these economic disadvantages by working cooperatively with other utilities to share resources and knowledge, particularly the resources necessary for plant refuelling outages. Two other potential offshoots of these economic factors are:

- Joint operating companies may be developed to operate a group of plants to achieve the economies of scale involved with the operation of several units.
- Joint service companies may be formed to achieve economies of scale in purchasing services and supplies.

An example of the latter was the formation in 1996 of a joint service company, Utilities Service Alliance, comprising 10 utilities owning 11 nuclear power plants, for the purpose of obtaining services and supplies for the utilities' nuclear plants.

Variable Factors

Another major factor in determining a plant's competitiveness is whether it will need to make significant capital expenditures in the near future in order to continue operating. Such capital expenditures are not sunk costs and, in a competitive marketplace, must be included in the cost of electricity generation that the plant must be able to earn in order for the expenditure to be economically justifiable to the owner. A plant that

is currently competitive but is anticipated to require a large influx of capital in the next several years is a less desirable economic asset and may simply be operated until the capital infusion is needed, and then shut down. The Zion plant is an example of this scenario.

The two largest capital needs typically facing existing nuclear plants are the cost to replace degraded steam generators, and the cost to replace or upgrade plant systems to achieve licence renewal. In addition to Zion, which will be shut down in the near future because of the need to replace its steam generators, the Trojan plant was shut down because the owner could not economically justify the cost of replacement steam generators necessary to operate the plant until the end of its licence period. The Yankee Rowe plant was shut down because its owners could not justify expending the capital to repair or replace its pressure vessel. The Yankee Rowe experience, however, may not be typical because of the plant's small size and early vintage.

Thus, the longer the period of time before a large influx of capital is needed to continue the operation of an existing plant, the more competitive the plant should be. Plants with robust or newly replaced steam generators, and plants that have a significant period of time remaining in their initial licence term, should in general be more economic in the competitive marketplace brought about by restructuring.

Regulatory Factors

A major uncertainty for nuclear power as the electricity industry enters the dawn of competition is the NRC's regulatory response to utility restructuring and deregulation. The regulatory actions of the NRC can have a tremendous economic impact on nuclear plants, collectively and individually, as reflected by the regulatory changes following the 1979 event at Three Mile Island, as well as the recent experience at the three Millstone plants.

Restructuring and the advent of a competitive marketplace for electricity is forcing the NRC to reflect on the appropriateness of its regulations in a competitive market. The NRC's regulations for nuclear power plants were developed in an era when franchised monopolies and rate regulation was the only model for the sale of nuclear electricity. Many of the NRC's regulations, particularly those that address licensees' financial qualifications, were built around the assumption that licensees would be guaranteed a fair rate of return on their prudent

power plant investments, and that expenses such as plant decommissioning would be fully funded before they were needed. As I will discuss in greater detail below, the NRC is currently evaluating what types of regulatory actions and approaches it should take in response to the restructuring ongoing in the electricity industry.

A potential major issue is the NRC's desire to ensure that the economic pressures of competition do not erode nuclear power plant safety. The nuclear industry has significantly reduced O&M costs already, and the forces of the competitive marketplace will lead licensees to reduce further plant O&M costs to the extent they believe to be consistent with plant safety. The NRC, as the regulator charged to protect public health and safety in connection with nuclear power, may have different views on whether various cost saving measures will endanger public health and safety by reducing plant safety margins.

In turn, many in the nuclear industry believe that the NRC's regulatory actions often do not focus on issues of true safety significance. Indeed, this viewpoint was echoed by one of the NRC commissioners at the NRC's annual Regulatory Information Conference in April 1997. Thus, the ultimate test for the future of nuclear power in the competitive marketplace may be whether utilities are able to operate their plants both efficiently and safely, and whether the NRC will be better able to focus its regulation on activities of true significance to plant safety.

Increases in Fossil Fuel Costs

The projected O&M costs of competing fossil fuel generation is the benchmark to which projected nuclear power O&M costs must be compared to assess their competitiveness. As I discussed earlier, the current average O&M cost for coal power is only slightly lower, and the cost for natural gas and oil power are far higher, than the average cost for nuclear power. As the O&M costs of fossil fuel generation increase, nuclear power becomes more competitive.

Increased regulation of fossil plant emissions could drive up the costs of fossil fuel generation. The restructuring debate has reopened discussions of inter-regional pollution equity. Some north-eastern states have expressed concern about anticipated substantial increases in the generation of coal power in the Midwest, driven by coal being the lowest cost fuel source in a competitive marketplace, and the resulting increase in acid rain and smog pollution problems downwind in

the northeast. These potentially affected states have lobbied for additional regulation of emissions from coal-fired plants as part of any legislation restructuring the utility industry.

At the same time, the issue of carbon dioxide production and global warming is again at the political forefront. Many environmental organisations and the Clinton administration are pushing to curb the generation of carbon dioxide in the United States, which would adversely affect all fossil-fuelled generation, including both coal and natural gas, but would not affect nuclear power.

Furthermore, the Environmental Protection Agency (EPA) is concurrently working to reduce the allowable levels of various air pollutants, including the production of nitrogen oxides, by mandating reductions in utility power plant emissions. All of these pollution control initiatives could drive up the O&M costs of some or all types of fossil-fired generation, which would make nuclear power more competitive in the restructured marketplace.

The Impact on Fuel Cycle Vendors

The effects of competition will trickle down from nuclear power plant owners to nuclear fuel cycle vendors, driving vendors to increase efficiency and decrease costs. The force of competition will drive nuclear power plant owners to search everywhere for ways to reduce plant O&M costs, and their search will ultimately lead to nuclear fuel cycle costs as a focal point for cost reduction efforts.

Nuclear power plant licensees will look to nuclear fuel cycle vendors, including uranium providers, enrichment services providers and fuel fabricators, to offer more attractive pricing options to increase the power plant's competitive position. This, in turn, will drive nuclear fuel cycle vendors to look for ways to increase efficiency and reduce prices in what is already a very competitive industry.

In addition, as competition intensifies and marginal nuclear plants are shut down, the demand for nuclear fuel cycle services will fall at a time when the supply of these services is, if anything, increasing. This fall in demand will likely create further downward pressures on prices, which would further exacerbate the competitive effects on fuel cycle vendors. Thus, restructuring and competition in the electricity generation industry will most likely force individual nuclear fuel cycle vendors to become more efficient if they want to continue to be a player in the competitive marketplace.

The NRC's Response to Restructuring

As mentioned above, a major uncertainty overhanging nuclear power as the electricity industry enters the competitive marketplace is the NRC's regulatory response to the changes taking place in the industry. The NRC is actively evaluating the restructuring and deregulation developments occurring in the utility industry and is currently considering the type of regulatory actions and approaches it should take in response to these developments.

In developing its proposed regulatory changes, the NRC has focused on its jurisdiction of protecting the public health and safety, and has repeatedly stated that it is not an economic regulator. In a recent speech at MIT, NRC Chairman Shirley Jackson addressed these changing circumstances, stating the commission's view clearly as follows:

"Our focus is on ensuring that, as the business environment changes, economic pressures do not erode nuclear safety. That means that nuclear electricity generators must continue to maintain high safety standards, with sufficient attention and resources devoted to nuclear operations, and with decommissioning funding secure . . . [I]t is not the NRC's mandate to ensure the economic viability of nuclear power or to jeopardise it, only to ensure that whenever nuclear power is used, it is used safely, and that, when a nuclear plant is shutdown, there is adequate funding to ensure that it can be decommissioned safely."¹⁵

The NRC's view on this point is thus clear. It considers that its fundamental responsibility is to assure the protection of health and safety in connection with nuclear power assets.¹⁶ Such statements, however well-intentioned, miss the point that carrying out health and safety regulation has an important economic component. There is a direct relationship between the health and safety requirements imposed by NRC regulation and the cost of power produced by a nuclear plant.

However, in the context of traditional utility rate regulation, the economic component of NRC's regulation has not been a matter of central concern to the commission. Prior to the advent of restructuring, the NRC could rely on the assumption that the costs associated with its health and safety regulatory requirements would be reflected in the rates established through utility rate regulation. The utility had a guaranteed market for the output of its nuclear plant and the purchasers were obligated to pay a rate for electricity based on the costs incurred in serving them, including costs growing out of NRC requirements.

In the restructured industry, however, generation assets will be disaggregated from the transmission and distribution systems through which their output is delivered. The price for generation output will be determined by market forces, either by prices paid at the wholesale level by operators of the grid or, eventually, in sales directly at retail level, with the end user arranging the delivery transaction over the grid.

In this setting, the costs associated with NRC health and safety regulation, along with all other costs of operating a nuclear facility, must be consistent with a price which is competitive with other forms of generation. Otherwise, the nuclear asset becomes non-economic. Thus, as I observed earlier, the ultimate test for the future of nuclear power in the new competitive environment may be whether utilities are able to operate their plants both efficiently and safely, and whether the NRC is able to focus its regulation on activities truly significant to plant safety.

NRC's Regulatory Actions To Date

Chairman Jackson's statement which I quoted above identifies the two major areas in which the NRC will consider the effects of a restructured electricity market: operational safety and decommissioning funding. At present the precise nature of the NRC's response is very much work in progress. The NRC has taken several actions since the start of 1996 indicating its intent to revise its regulations and practice in response to restructuring initiatives. Thus far, however, other than a new proposed rule on decommissioning funding, the NRC has simply put the industry on notice that changes can be anticipated.

The official actions taken to date by the NRC to address electricity utility restructuring and deregulation are shown in Table 1. This shows that the NRC is actively tracking and evaluating the changes occurring in the electricity utility industry but, as yet, has taken few concrete regulatory actions. Some of the major areas under discussion are described below.

Thus far, however, there has been no indication that a dramatic change in the NRC's current policies and programmes is perceived as necessary. Rather, the NRC appears to believe that its current regulatory structure, with some modification, can continue to provide adequate protection of the public health and safety in a restructured environment. In this regard, Chairman Jackson has expressly stated her belief that the safe operation of nuclear facilities is not inconsistent with cost

recovery through market-based pricing.¹⁷

Transmission Grid Reliability

The only technical safety issue related to restructuring raised by the NRC is grid reliability. The effect of selling electricity in a competitive marketplace at spot market prices in place of long term regulated rates may lead to reductions in the reserve margins available on the system. Reductions in reserve margins and unregulated fluctuations in supply could challenge the reliability of the electricity grid, given the constant fluctuations in electricity demand curve as a function of time and other less predictable factors, including local weather and unforeseen power loss.

In 1996 two electricity grid disturbances in the western United States shut down much of the western grid and caused many power plants, including several nuclear plants, to trip off-line. Although several factors have been cited as contributing to these events,¹⁸ they have collectively raised fears that additional power disruptions or rolling blackouts could be expected in a deregulated environment.

Grid reliability is a key assumption in the NRC's station blackout analysis. The likelihood of loss of off-site power from the electrical power grid is a primary input to the NRC's evaluation of the likelihood of station blackout events, in which a nuclear plant loses both off-site power from the grid and on-site power from, typically, diesel generators. While the assumptions in the existing analyses are extremely conservative, the commission has requested its staff to evaluate whether decreases in grid reliability associated with restructuring will challenge the original assumptions.

Independent of the NRC, electricity industry efforts are underway to establish mechanisms to ensure continued grid reliability as restructuring unfolds. Grid reliability is currently monitored and addressed by a voluntary organisation, the North American Electricity Reliability Council (NERC). In January 1997 NERC's board of trustees voted to make compliance with its reliability policies mandatory for those utilities that participate in NERC. FERC has recommended that federal legislation be passed to make participation in NERC mandatory for all electricity generators subject to federal jurisdiction. The electricity utility trade organisation, the Edison Electric Institute, is also heavily focused on the grid reliability issue. Additionally, both federal and state legislators now routinely discuss grid reliability as an

Table 1. Official actions taken by the NRC to address electricity utility restructuring and deregulation.

1. NRC Briefing Session, 14 December 1995. NRC public meeting in which industry representatives (federal and state regulators and industry and investment officials) briefed the commission on restructuring issues.
2. NRC Briefing Session, 5 January 1996. NRC public meeting in which the NRC staff briefed the commission on its near term, mid term, and long term action plan to address restructuring issues.
3. *Financial Assurance Requirements for Decommissioning Nuclear Power Reactors*, Advanced Notice of Proposed Rulemaking (ANPR), 8 April 1996 (61 Fed. Reg. 15 427, 1996). The ANPR indicated that the NRC was considering clarifying its regulatory definition of 'electricity utility' in light of restructuring. It also indicated that the NRC was considering holding companies jointly and severally liable for decommissioning costs, a viewpoint it later rejected in the subsequent proposed rule approved for publication at the end of June 1997 (see point 11 below).
4. *Action Plan for NRC Response to Electric Utility Industry Restructuring and Economic Deregulation*, 15 May 1996. This document indicates NRC's interest in financial qualifications, decommissioning funding and antitrust reviews. Rulemaking is contemplated concerning NRC approval for all licensee corporate changes that significantly reduce assets or recourse to rate recovery. Of considerable interest is the indication that NRC is considering requiring its approval for a licensee sell-off of non-nuclear assets such as fossil plants or gas operations. The action plan includes schedules for revision of standard review plans (draft 8/96 and final 6/97). With regard to rulemaking, the plan contemplates determining the need for rulemaking by mid 1997, with a schedule to be determined.
5. NRC Briefing Session, 30 July 1996. NRC public meeting in which the NRC staff briefed the commission on the status of NRC's actions in response to electricity utility restructuring and deregulation.
6. *Final Policy Statement on the Restructuring and Economic Deregulation of the Electric Utility Industry*, 19 August 1997 (62 Fed. Reg. 44 071). The NRC notes that co-owners generally divide costs and output from their facilities on a pro rata basis according to the respective ownership shares of the co-owners. In the Final Policy Statement, however, the NRC acknowledges that it "has implicitly accepted this practice in the past and that it should continue to be the operative practice" in the future, but it "reserves the right, in highly unusual situations where adequate protection of public health and safety would be compromised if such action were not taken, to consider imposing joint and several liability on co-owners . . . when one or more co-owners have defaulted". this position conflicts, at least in tone if not substance, with that taken by the NRC in the proposed rule for decommissioning funding that there is "no need to impose an additional regulatory obligation of joint liability on co-owners" with respect to decommissioning funding. (see point 11 below).
7. *Draft Standard Review Plans on Antitrust and Financial Qualifications and Decommissioning Funding Assurance*, 27 December 1996 (61 Fed. Reg. 68 309, 1996). These draft standard review plans reflect NRC's current regulations and do not provide the final NRC position.
8. NRC Briefing Session, 23 April 1997. NRC public meeting in which industry representatives (federal agency and industry officials) briefed the commission on electricity grid reliability issues, including the operation of power pools and voluntary grid reliability councils, and the anticipated effects of restructuring.
9. NRC Briefing Session, 24 April 1997. NRC public meeting in which the NRC staff and industry representatives (federal and state regulators and industry officials) briefed the commission on emerging issues related to electricity utility restructuring. The NRC staff stated it will develop a paper identifying policy options to address general financial qualifications. Grid reliability, antitrust review, and foreign ownership limitations were also identified as emerging issues that the staff should address. The commission is considering seeking legislation to eliminate its antitrust review requirements. The staff stated its intention to establish clearer standards on limitations of foreign ownership of domestic nuclear power plants.
10. NRC Staff Meeting, 19 June 1997. NRC staff public meeting in which the NRC staff presented the status of its activities addressing grid reliability and utility restructuring. The commission requested the staff to address the impact of restructuring on grid reliability and evaluate the possible impact of decreased grid reliability on station blackout analysis for nuclear power plants. The staff stated its intent to develop a task action plan defining the steps it will take to evaluate the grid reliability issue.
11. *Proposed Rule on Financial Assurance Requirements for Decommissioning Nuclear Power Reactors*, 30 June 1997. The proposed rule would change the regulatory definition of an electricity utility to include entities that recover the cost of electricity 'indirectly through another non-bypassable charge mechanism' in addition to traditional cost of service regulation. This new definition would encompass decommissioning funding through legislated stranded cost recovery mechanisms such as non-bypassable wire charges on ratepayers in the nuclear power plant's original service area. The proposed rule would also require nuclear plant licensees to periodically report to the NRC on the status of their decommissioning funds and changes in their trust fund agreements. In developing the proposed rule, the NRC determined that joint and several liability for decommissioning costs is not appropriate and it was not included in the proposed rule, as originally considered in the April 1996 ANPR.

important factor to consider in restructuring legislation.

The NRC has initiated regular communication with all of these organisations on grid reliability. The NRC is also working with existing power pools and power marketing organisations, which could become the independent system operators for the competitive marketplace, on issues such as protocols for restarting power plants following grid disturbances. These efforts indicate that maintaining grid reliability is a matter of fundamental concern well beyond the nuclear power industry, and that steps taken on a nationwide level to assure continued grid reliability for economic and other reasons will assure that grid reliability remains well within the assumptions made in the current NRC station blackout analyses.

Financial Qualifications – Overview

The unbundling of generator assets and the elimination of such assets from the regulated ratebase in restructuring has focused the NRC's attention on licensees' continued financial qualifications both to conduct operations and to continue to fund nuclear power plant decommissioning following the advent of competition. NRC regulations on general financial qualifications and decommissioning funding are currently relatively limited for licensees that meet the NRC's definition of an electricity utility. The NRC's current regulations define an electricity utility as an entity which recovers its costs through rates established either by the entity itself or by a separate regulatory authority.¹⁹

The loss of guaranteed ratebase treatment of generation assets as a result of restructuring may well cause the NRC to challenge whether an existing or new entity will meet its definition of an electricity utility. The NRC has already made this point in commenting on the potential purchase of a nuclear power plant, Maine Yankee, by an existing electricity utility, PECO. After the purchase, the nuclear plant would be operated as a generation asset selling wholesale power on the electricity grid, but without captive ratepayers.

Robert Wood, a senior financial analyst on the NRC staff, was reported as stating that a wholesaler without cost of service ratemaking recovery for the sale of power was not likely to qualify as an electricity utility under the NRC's regulations.²⁰ That would mean that PECO, even though it is defined as an electricity utility for its current nuclear power plants, would have to demonstrate financial qualifications for operations and decommissioning

funding under the more onerous requirements for a "non-utility". This scenario could be faced by both new and existing entities which purchase nuclear power plant assets, and may also be applied to existing licensees whose regulatory environment changes as a result of restructuring to the extent that they no longer meet the NRC's regulatory definition of an electricity utility.

Financial Qualifications for Operations

Currently, the NRC reviews an entity's financial qualifications for operations only in the context of an application for an operating licence or the transfer of an existing operating licence to a new owner. If the licence applicant or licence transfer applicant meets the NRC definition of an electricity utility, it need not further demonstrate its financial qualifications. The NRC has made a generic determination that the ratemaking process provides reasonable assurance that a utility will have the funds necessary to operate a facility safely.²¹

However, if the applicant does not qualify as an electricity utility, it must "submit information that demonstrates the applicant possesses or has reasonable assurance of obtaining the funds necessary to cover estimated operation costs for the period of the licence". The applicant must estimate the costs for each of the first five years and indicate the sources of funds to cover those costs.²² This requirement applies to all owners that do not qualify as an electricity utility, including those that are only licensed to possess or own a part interest in a nuclear plant and are not authorised to operate the plant.

In the context of a transfer of nuclear plant ownership, a licence transfer applicant which does not qualify as an electricity utility might also fall into the category of "newly formed entity" under the NRC's regulations. This is an entity "organised for the primary purpose of constructing or operating a facility". If this is the case, the newly formed entity must provide additional financial information, including:

- the legal and financial relationships it has or proposes to have with its stockholders or owners;
- its financial ability to meet any contractual obligation it has incurred or proposes to incur;
- any other information considered necessary by the NRC to determine the applicant's financial qualifications.²³

It should be noted, however, that the present regulation provides little guidance as to what constitutes "reasonable assurance" sufficient for the approval of a licence transfer to entities that

do not qualify as electricity utilities.²⁴ A significant recent Atomic Safety and Licensing Board (ASLB) decision has interpreted these provisions as requiring a great degree of certainty with regard to showing sufficient funding.²⁵ The ASLB's decision, however, has been appealed to the NRC.²⁶ In an amicus brief, the Nuclear Energy Institute (NEI) has argued that there are serious legal errors in the ASLB's decision.

The NRC staff is taking a broad look at its general financial qualifications requirements in the context of restructuring and has stated its intent to develop a paper in 1997 which identifies policy options. This review could result in rule-making to revise the NRC's financial qualifications requirements. There is some indication that the staff is exploring a set of financial qualifications which takes a flexible, totality of circumstances approach, rather than stating formulaic standards (such as reliance on bond ratings).²⁷

It is clear that, whatever set of general financial qualifications requirements it puts in place for licence transferees, the NRC will continue to rely primarily on its inspection programmes in a restructured environment to assure public health and safety. In her MIT speech, Chairman Jackson identified the NRC's central concerns with restructuring in the terms I have already quoted. She immediately went on to say:

"The NRC traditionally has relied on its inspection and plant assessment programmes to identify any adverse trends in safety performance. Based on inspection programme results, plant performance reviews, and other evaluative mechanisms, the NRC can take action it deems appropriate to protect public health and safety. In the current economic environment, if new business arrangements, competition, or economic constraints result in any impairment of safety, it is imperative that our assessment mechanisms detect such problems early."²⁸

Other speeches by the NRC Chairman have similarly indicated that the NRC intends to rely on early detection of adverse trends to assure safe operation in a competitive setting.²⁹

It seems clear, therefore, that entities contemplating transfers of nuclear assets or operating without cost of service ratemaking should anticipate that the NRC's traditional concern with safe operations will continue unabated; that the NRC will be developing inspection programmes focusing on early indication of adverse trends arising from cost-saving measures; and that the financial qualifications for operations which must be met

by new entities and entities operating without a regulated ratebase will be addressed by the NRC in new regulations whose parameters are presently uncertain. Of course, it must always be borne in mind that the ultimate tool available to the NRC if its safety concerns are not satisfied is shutdown of the nuclear facility.

Financial Assurance for Decommissioning

The other financial area of primary interest in restructuring is decommissioning funding. The NRC seeks reasonable assurances that decommissioning funding will be available at the time a plant is decommissioned. There are three financial mechanisms in the NRC's regulations for providing that assurance:

- prepayment;
- an external sinking fund;
- a surety method, insurance, or other guarantee method.³⁰

Prepayment must be made, prior to the start of operation, into an account segregated from a licensee's assets and outside its administrative control. An external sinking fund is established by setting aside funds periodically into an account segregated from licensee control. A surety method may be in the form of a surety bond, letter of credit, or line of credit. The NRC's regulations establish a minimum amount of financial assurance for various categories of plants, but does allow utilities to set aside greater amounts than the minimum required by the regulation.³¹

As with financial qualifications for operations, the status of the licensee becomes crucial. If a licensee is an electricity utility, it can choose between all three methods.³² In practice, licensees classified as utilities have elected to use the external sinking fund method. This funding method is consistent with the way regulated utilities recover costs.

However, if an applicant does not qualify as an electricity utility, it can use the prepayment and surety methods, but it cannot elect for the external sinking fund method alone. If such an entity elects to use the external sinking fund method, it must couple that mechanism with the surety method for the entire unrecovered part of the decommissioning cost estimate.³³ This can be a considerable burden in practice when compared with the "pay as you go" system available to utilities. On these decommissioning funding arrangements, there is no heightened requirement for applicants that are newly formed entities.

Restructuring also alters the fundamental assumptions underlying the NRC's decommis-

sioning funding requirements for electricity utilities. Current NRC regulations allow utilities to fund decommissioning costs over the productive life of the plant, even though such costs are committed at the outset of plant operations. This approach is based on the traditional utility paradigm of a regulated monopoly, ie. that the recovery of these costs was assured through rates authorised by the applicable federal or state regulatory authorities. It is, however, precisely this paradigm that restructuring and deregulation of the utility industry will alter.

The potential impact of restructuring on the NRC's underlying assumptions for decommissioning funding has been widely recognised and discussed. The need to recover decommissioning costs in a competitive market where prices are based on marginal costs could render some nuclear assets uneconomic. Thus, decommissioning costs which would have this effect are viewed as falling into the category of stranded costs. As I discussed earlier, however, it seems to be the prevailing regulatory and public policy view that, as part of the restructuring process, stranded cost recovery for nuclear plant decommissioning is viewed as a public health and safety imperative and that mechanisms must be put in place to assure the recovery of decommissioning costs (as well as other stranded costs).³⁴

Generally speaking, this involves identifying the magnitude of the stranded costs, including decommissioning costs, not yet recovered at the time of the shift to a competitive market. A non-avoidable charge, such as a charge for the use of transmission wires to deliver the power purchased, is then put in place for a fixed period of time. Through that charge the stranded costs are recovered from the customers which would have been responsible for them in the regulated mode.

In June 1997 the NRC approved publication of a proposed rule that would revise the financial assurance requirements for decommissioning funding of nuclear power plants.³⁵ The most significant change in the proposed rule would be to alter the regulatory definition of an electricity utility. Although not the subject of the proposed rule, such a change in the definition of an electricity utility would also apply to demonstrating financial qualifications for operations, discussed above.

For an entity to qualify as an electricity utility under the proposed rule, it would have to recover the cost of electricity through "rates established by a regulatory authority . . . directly through traditional cost of service regulation or indirectly

through another non-bypassable charge mechanism". In turn, the proposed rule provides the following definitions for cost of service regulation and non-bypassable charges as follows:

- Cost of service regulation means the traditional system of rate regulation in which a rate regulatory authority allows an electricity utility to charge its customers all reasonable and prudent costs of providing electricity services, including a return on the investment required to provide such services.
- Non-bypassable charges means those charges imposed by a governmental authority which affected persons or entities are required to pay to cover costs associated with operation, maintenance and decommissioning of a nuclear power plant. Affected individuals and entities would be required to pay those charges over an established time period.

Thus, the NRC would continue to treat licensees that recover decommissioning costs through a non-bypassable charge as electricity utilities under its regulations, at least insofar as decommissioning costs are concerned.

With respect to decommissioning funding requirements for non-utilities, the NRC has proposed no rule changes, despite recognising that the requirements of the present regulation can be onerous. For example, the NRC notes that "requiring full up-front funding in advance", which is essentially what the present rule requires, "would be overly burdensome if applied to all licensees". In the draft regulatory impact analysis for the proposed rule — which addresses the impacts of the proposed rule on licensees that are no longer defined as electricity utilities — the NRC notes the difficulty entailed in obtaining a surety for the unrecovered part of a licensee's decommissioning cost estimate. The NRC states:

"There are likely to be limits on the availability of surety bonds and other third-party guarantee financial mechanisms, such as letters of credit and lines of credit, to nuclear reactor licensees that are required to obtain such mechanisms to demonstrate financial assurance for the difference between their external sinking funds and the full amount of required assurance if the licensee no longer qualifies as an "electricity utility". These limits may be created by the possibility, on the one hand, that the nuclear reactor licensees will no longer have recourse to the asset base of the utility, and that, on the other hand, providers of such financial mechanisms will require high levels of collateral and security before they will make such mechanisms

available.

“[T]he providers of financial mechanisms such as surety bonds and letters of credit have frequently required collateral for a portion or the full amount of the mechanism, and there is no reason to expect that they will relax this requirement for mechanisms assuring the very large decommissioning costs of nuclear generating facilities. Generating [companies] without access to substantial assets may find it difficult to provide the necessary collateral.”

Though the NRC identifies adverse financial impacts on licensees that would no longer be considered to be electricity utilities, it provides no proposed solution. Thus, any entity that does not have stranded cost recovery for decommissioning funding through non-bypassable charges will have to meet the additional economic burden of not only accumulating funds for decommissioning, but also either paying those funds up front or paying the cost of a surety bond until the funds are collected. The Commission has approved changes to the statement of considerations of the proposed rule requesting comments on whether accelerating decommissioning funding for non-electric utilities might serve to alleviate the burden. Absent some relief, the proposed rule could seriously discourage nuclear utilities, such as PECO, and other entities from purchasing nuclear plants, such as Maine Yankee currently under consideration by PECO.

The proposed rule would also require nuclear power reactor licensees to report every two years on the status of their decommissioning funds and changes in their external fund agreements. This requirement would allow the NRC to monitor the rate of fund accumulation relative to the life of the plant to ensure that sufficient funds will have been collected by the time of decommissioning.

On a beneficial note, the proposed rule would expressly allow licensees to take credit for earnings on accumulated decommissioning trust funds both during the operating and decommissioning periods. Under this rule, earnings on the trust fund following plant shutdown can expressly be used to meet decommissioning funding requirements.

NRC Antitrust Reviews

Another issue which has been raised in the NRC's consideration of restructuring is the possibility of eliminating the commission's antitrust review. The NRC's practice for plants subject to the antitrust review requirement has been to perform a threshold "significant change" antitrust review when a nuclear

power plant licence is transferred to a new owner.³⁶ This review has been done in parallel with the antitrust review jurisdiction of FERC, the SEC and the Federal Trade Commission.

Antitrust issues might not arise at all, depending on the plant's age and the nature of the restructuring. Under Section 103 of the Atomic Energy Act, the NRC's antitrust review responsibilities pursuant to Section 105 apply only to plants which received construction permits after 19 December 1970.³⁷ Furthermore, if the licence transfer involves merely the indirect transfer of control from an existing licensee to a new holding company, no new licence is issued and there is no need for a review.³⁸

It is difficult to predict with certainty the role of antitrust issues in an NRC review of a nuclear power plant asset transfer arising from restructuring initiatives under the current statutory requirements. There is reason to conclude, however, that this will not be an area of significant concern in restructuring. The NRC has recognised that its antitrust review significantly overlaps antitrust reviews performed by FERC, the FTC, the SEC, and the Department of Justice and has stated its intent to pursue eliminating its duplicative antitrust efforts through an amendment to the Atomic Energy Act. The NRC has not yet, however, taken any specific actions to pursue legislation.

For the time being, the NRC's statutory responsibility to consider antitrust aspects of asset transfers continues to exist. Accordingly, the possibility of its use or expansion in a restructured marketplace where significant asset transfers can be expected to occur cannot be ignored.

Foreign Ownership Limitations

Another issue which the NRC has raised with the advent of restructuring is how it should revise its current limitations on foreign ownership. Current NRC regulations require that a licensee not be "owned, controlled or dominated by an alien or foreign government".³⁹ The specific limits of the foreign ownership limitation requirement are unclear. Restructuring and competition may provide opportunities for beneficial participation by foreign entities in the operation and ownership of US nuclear power plants, which will require the NRC to clearly define the extent of its foreign ownership limitations.

It has been recommended that the NRC either seek repeal or revise the current limitations on foreign ownership.⁴⁰ The limitation could be repealed by amending the Atomic Energy Act. Alternatively, it could be revised by the NRC

loosening its narrow interpretation of the act's prohibition on foreign ownership, control or domination. The NRC staff has stated that it wants to establish a percentage threshold of foreign ownership below which it would not perform a detailed review of whether a proposed licensee is under foreign ownership, control or influence, but no clear standards have yet been articulated.

The NRC staff has stated its anecdotal opinion that over 50% foreign ownership of a licensee would probably contravene the Atomic Energy Act, whereas a less than 5% foreign interest would probably be considered *de minimis* and not contravene the act. It was noted that the issue will be faced the first time an applicant with some material foreign ownership seeks to become a nuclear power plant licensee. The NRC staff has taken no additional public action on this issue to date.

Conclusion

The march to a competitive marketplace for the sale of electricity in the United States has been proceeding at a rapid pace at both the federal and state levels. While many of the nuclear plants in the USA appear to be well placed to operate in a competitive market with their relatively low O&M costs, a handful are potentially uneconomic and are subject to being shut down as the industry undergoes the transition to competition. Indeed, some nuclear power plants have already shut down for economic reasons.

These potential consequences will drive nuclear power plant licensees to search for further ways to reduce plant O&M costs as restructuring approaches. This drive to reduce costs can, in turn, be expected to put pressure on nuclear fuel cycle vendors to further reduce their costs. Restructuring will bring a renewed focus on efficiency and cost margins to the entire nuclear power industry.

At the same time, the industry focus on efficiency and cost margins will be closely reviewed by the NRC to ensure that it does not reduce what the NRC believes are appropriate and necessary safety margins. The NRC's regulatory response has yet to be fully defined and remains a significant source of uncertainty for the nuclear industry as competition looms.

It can, therefore, be said with certainty that creation of a competitive market poses serious questions about the economic future of existing nuclear capacity. The answers to these questions, however, are far from clear. Nuclear capacity

constitutes about 14% of total generating capacity in the USA and about 21% of actual electricity output. Regionally, nuclear power can play an even more important role, particularly in the northeast and the upper Midwest. Moreover, nuclear generation is regarded as environmentally desirable in regions facing serious air emissions problems. It is also desirable for a variety of reasons to maintain a diversity of generating resources.

Thus, it is by no means clear that public policymakers fostering the competitive market will accept the loss of a significant part of this segment of the nation's generating capacity as a consequence of their interest in achieving the benefits of restructuring. The uncertainties about electricity pricing trends, O&M cost trends, and potential NRC regulatory actions do not yield irrefutable answers as to future of nuclear power in a competitive marketplace.

References and Footnotes

1. Following the trend of encouraging settlement of disputes outside of agencies and the courts, Order 888 also requires that all transmission disputes between public utilities be subject to informal negotiation and voluntary arbitration.
2. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, Docket No. RM95-8-000, IV FERC Stats. & Regs. par. 33 085, 1995.
3. However, many companies that both provide transmission services and generate power may voluntarily choose corporate unbundling in the new regulatory regime.
4. As with Order 888, Order 889's requirements can be waived by FERC in extenuating circumstances.
5. See, Federal Regulatory Commission, *Fact Sheet: Highlights of the Open Access Proposal*, 29 March 1995.
6. Gasparino C & Zuckerman G, *Changing world of utilities will give bonds a new spin*, Wall Street Journal, 16 June 1997. See also, *In regulatory landscape, electricity derivatives may have bigger future*, Daily Report for Executives, 11 June 1997.
7. For example, after a 1994 surprise state utility commissioner's proposal in California, three large utilities in the state lost over US\$5 billion in market value. See, *Federal action on utility restructuring should avoid harming stock, bond holders*, Daily Report for Executives, 23 May 1997.
8. See, *Markey to unveil retail choice measure; Bumpers fears Senate will pass PUHCA bill*, Daily Report for Executives, 5 June 1997.
9. Although HR655 requires retail competition in all states by 2001, Representative Schaefer has indicated his willingness to consider a later date to allow states time to implement competitive plans.
10. *Would deregulated power be reliable?*, Congressional Green Sheets Weekly Bulletin, 16 June 1997.
11. National Regulatory Research Institute, *Electric Industry Restructuring Box Score*, 30 April 1997.
12. California ranked seventh out of the fifty states in 1993 in cost per kilowatt hour for the industrial sector. See, *Annual Electric Utility Report*, USDOE Energy Information

- Administration, January 1995.
13. *Fearing write-downs of \$800 million, PSNH says stranded cost policy will sink New Hampshire giant*, Electric Power Alert, 19 January 1997.
 14. Oregon, after very similar efforts, also failed to pass restructuring legislation in 1997.
 15. Jackson SA, *A physicist's path: from multiperipheral models and superlattices to the US Nuclear Regulatory Commission*. Address to the National Conference of Black Physics Students at MIT, 28 February 1997, in NRC Office of Public Affairs, no. S-97-05, 28 February 1997 (hereinafter 'Chairman's MIT Speech'). See also, Jackson SA, *Nuclear energy and economic competition: the NRC perspective*. Keynote address to Nuclear Energy Institute Fuel Cycle '97, Atlanta, 7 April 1997 (hereinafter 'Chairman's Atlanta Speech') (stating, 'it is important that the NRC not be influenced in making safety regulatory decisions by the need to lower the cost of operating a nuclear plant... [L]et me reiterate that the NRC will continue to take seriously its responsibility as a safety regulator').
 16. See also, Jackson SA, *Economic deregulation of the electric utility industry: ensuring nuclear safety in an era of changing operational and financial perspectives*. Keynote address to Annual Meeting of Nuclear Electric Insurance, 17 June 1997, in NRC Office of Public Affairs, no. S-97-16, 26 June 1997 (hereinafter 'Chairman's NEI Speech').
 17. See for example, Chairman's NEI Speech (stating, 'I firmly believe that ensuring safety is in no way inconsistent with economic deregulation and competition'); Chairman's Atlanta Speech (stating, 'my own view is that adequate protection of public health and safety is entirely compatible with a deregulated environment, provided economic restructuring of the electrical power industry addresses what is necessary for that protection').
 18. The Western Systems Coordinating Council, reviewing the incidents, listed several possible factors: high northwest transmission loads; equipment out of service; inadequate maintenance of right-of-way; operation in a condition in which a single failure would overload parallel lines, triggering cascading outages; communication failures to neighbouring utilities, prior to the disturbances; and the lack of response to earlier events. See Chairman's NEI Speech.
 19. 10 CFR §50.2.
 20. *An NRC review of future PECO-Maine Yankee sale could plow new ground*, Inside NRC, 7 July 1997.
 21. 10 CFR §50.33(f).
 22. 10 CFR §50.33(f)(2).
 23. 10 CFR §50.33(f)(3)(i-iii).
 24. See, 10 CFR §50.33(f)(2).
 25. Louisiana Energy Services Claiborne Enrichment Center, 44 NRC 331, 1996. Although the ASLB's decision dealt with licensing of enrichment facilities under 10 CFR Part 70, the ASLB applied and interpreted the rules governing reactor licensing under 10 CFR Part 50.
 26. In, re Louisiana Energy Services, LP 45 NRC 49, 1997 (granting review).
 27. See for example, Chairman's Atlanta Speech (stating, '[r]egulatory changes might include eliminating any ambiguities in the NRC definition of 'electricity utility', and taking account of alternative methods of providing assurance of decommissioning funding – for example, pooled insurance, if available, or accelerated funding of decommissioning'). See also, Jackson SA, *Nuclear power in a competitive era*. Address to National Association of Regulatory Utility Commissioners, Conference on Nuclear Energy in Competitive Electricity Markets, Fort Myers, Florida, 23 January 1997, in NRC Office of Public Affairs, no. S-97-01, 23 January 1997 (hereinafter 'Chairman's Fort Myers Speech').
 28. Chairman's MIT Speech. See also, Jackson SA, *Striving for equality in a culturally diverse society*. Address to Rensselaer Polytechnic Institute, Troy, New York, 24 March 1997, in NRC Office of Public Affairs, no. S-97-06, 24 March 1997.
 29. See, Chairman's NEI Speech (stating, 'the NRC is developing objective, meaningful, 'leading' performance indicators of nuclear plant performance, as well as an enhanced approach for monitoring and assessing licensee corrective actions'); Chairman's Atlanta Speech (using essentially the same language to describe the NRC staff's activities).
 30. 10 CFR §50.75(e)(1)(i-iii).
 31. 10 CFR §50.75(b) and (c).
 32. 10 CFR §50.75(e)(3).
 33. 10 CFR §50.75(e)(2).
 34. See, Chairman's Fort Myers Speech (stating, 'Without being specific about how nuclear 'stranded' assets should be addressed by state public utility commissions or state legislatures, I will just say – it is important that our power reactor licensees continue to have sufficient resources to operate and decommission their plants safely'). See also, Chairman's Atlanta Speech (using essentially identical language); Chairman's NEI Speech (same).
 35. *Proposed Rule on Financial Assurance Requirements for Decommissioning Nuclear Power Reactors*, SECY-97-102, 16 May 1997 (approved by the NRC for publication on 30 June 1997).
 36. 10 CFR §50.80(b), 50.33a, 50.22, 2.101(e) and 2.102(d); 42 USC §2135(c)(2), 1996 (stating, antitrust review by the Attorney General 'shall not apply to an application for a license to operate a utilization or production facility for which a construction permit was issued under section 2133 of this title unless the Commission determines such review is advisable on the ground that significant changes in the licensee's activities or proposed activities have occurred subsequent to the previous review by the Attorney General and the Commission under this subsection in connection with the construction permit for the facility').
 37. 42 USC §2135(c)(8), 1996.
 38. See for example, *Safety Evaluation by the Office of Nuclear Reactor Regulation Related to the Indirect Transfers of Control of License Nos. DPR-66 and NPF-73 for Beaver Valley Power Station, Unit Nos. 1 and 2*. Docket nos. 50-334 and 50-412, 19 June 1997.
 39. See, 42 USC §2133(d); 10 CFR §50.80(b) and 50.33(a)-(d).
 40. See, *Nuclear Regulatory Commission Staff and Industry Briefing to the Commission*, 24 April 1997.