VIRGINIA STATE CORPORATION COMMISSION

STAFF INVESTIGATION ON THE RESTRUCTURING OF THE ELECTRIC INDUSTRY

II. HISTORY AS A GUIDE

In this section of the report we look to the past to examine why electric utilities were regulated in the first place. There are certain characteristics of the electric industry that make it unique. It is necessary to consider these traits to evaluate whether the industry itself has changed in a manner which justifies increased competition or whether outside forces have altered the traditional regulatory symmetry. We review the current method of regulation including incentives and disincentives such regulation provides utilities and their customers. Some successes and failures of traditional regulation are recognized. Next, we describe a series of events that have contributed to the current push for a restructured electric industry. Also included in this chapter are lessons we may learn from the deregulation of other industries in the United States.

A. Why Regulate the Electric Industry

Our country's roots are firmly planted in capitalism and the free market system; yet economic regulation has been, and in all likelihood will continue to be, necessary to remove barriers and distortions that impede competition and to assure the greatest degree of social benefit within the system. The scope and direction of regulation, however, tends to expand and contract over time with shifts in economic conditions, prevailing ideology and market characteristics.

For decades, the accepted belief has been that the public interest is best served with an electric industry comprised of franchised public utility monopolies that are subject to comprehensive regulation. That view has been challenged in recent years, and as a result, the electric industry is at a crossroads. It is appropriate that before debating how the industry should be structured in the future, we should look at the reasons for regulating the electric industry in the first place. Abraham Lincoln once counseled, "*If we could first know where we are, and whither we are tending, we could then better judge what to do, and how to do it*."

<u>Beginning of Electric Utility Regulation</u>

The early years of the electric industry were chaotic. Cities often had competing electricity suppliers, some providing alternating current and some direct current. For instance, in Chicago in the late 1800s, 29 franchises had been granted to electricity providers.

Samuel Insull of Chicago Edison was one of the leaders in addressing the economics of the industry. He recognized that the electric industry had high fixed costs because of the generating units needed to produce power and the transmission and distribution lines needed to distribute the power. On the other hand, the variable costs, or costs of operating the plants, were fairly low. He saw that the way to make money in the industry, and the way to be efficient, was to build large power plants and keep them running as often as possible.

However, the competitive nature of the industry in the early years proved hazardous to electric companies because of the high-fixed-cost/low-variable-cost characteristics just discussed. With displays of "*cutthroat competition*," prices were lowered until only variable costs were covered in an attempt to ruin competitors. While this proved good for the customers in the short term, once the competition was destroyed, or purchased, the winner could raise prices indiscriminately.

In 1898, Insull, as president of the National Electric Light Association ("NELA"), proposed that electric utilities be regulated by state agencies. This idea was not popular at first among the investor-owned companies, but it gained favor when the number of municipal systems tripled between 1896 and 1906. The public appeared to favor municipal electric systems over unregulated investor-owned systems. In 1907, the National Civic Federation and NELA spoke out in favor of state regulation of electric companies because they preferred state regulation over the development of municipal systems. Within ten years, 33 states had agencies that regulated the sale of electricity.

Industry Characteristics

There are several characteristics of the electric industry that made it particularly susceptible to regulation. Some of these characteristics have changed over time, particularly in the electric generation arena.

The predominate reason for regulating electric industry has been the belief that it is a natural monopoly industry. Monopolies are effective where a single firm can produce a desired level of output at a lower total cost than two or more firms. There are several reasons for this, including the realization of economies of scale whereby increased output leads to lower cost per unit produced. This relates to the high-fixed-cost/low-variable-cost of the electric industry recognized by Insull.

The provision of electricity has been considered a local enterprise. Other capital-intensive industries, such as the production of steel, can make a profit by securing a small portion of an international market. The electric industry has been structured with companies controlling the entire market in a franchised region. This has prevented needless and cumbersome duplication of facilities, such as using several power lines to serve a single neighborhood.

The electric industry is unique in that it takes energy from primary sources, such as coal or uranium, and converts it into electricity that is then transported to customers. Other forms of energy we use, such as natural gas or fuel oil, can be delivered directly to the customers' premises. A complexity that the industry must deal with is that electricity cannot be stored effectively; it must be generated at the time it is needed. This is further complicated by the fact that customers' usage patterns vary both on a daily and seasonal basis. Demand for electricity is naturally higher during the day than at night, and demand during a hot summer day loads the system more than the demand during a pleasant spring afternoon. The electric utility, however, must be prepared to meet its demand at the time of peak usage. This causes the construction of generating capacity that may sit idle for most hours of the year.

The need for adequate generating capacity and the long lead times needed to secure permits and construct a unit have created a complex and important planning function for electric utilities. It has been widely assumed that the long lead time and large capital cost of capacity additions would have made it difficult to secure financing for the development of our electric system without franchised service territories and regulation which allowed a reasonable return.

The U.S. electric industry has developed a reliable system that provides a vital service for our economic strength and social well-being. There is no substitute for electricity in many everyday functions. Electricity is flexible, safe, controllable, and relatively clean. Our dependence on electricity is best demonstrated by the hardships endured during the infrequent occasions that we are without power for a sustained period of time. Perhaps it is this strong public need for electric service that most distinguishes the industry.

Public Need

Earlier in this chapter it was mentioned that economic regulation is an important component of a free market system. This is because free markets may not or cannot always protect some individuals from suffering economic losses when others manage economic gains.

There is a long history of economic regulation, and few of the activities that have been regulated were natural monopolies. For the most part, services or products of importance to the public have been regulated. Early examples in England include ferries, common carriers, bakers and innkeepers.

The seminal case in the U.S. addressing regulation and the public need was *Munn v. Illinois.* That case involved an Illinois law passed in 1871 that established the rates that could be charged by grain elevators. Chief Justice Waite, in the majority opinion, quoted Britain's Lord Chief Justice Hale, who lived in the 1600s. Hale found that when private property is "*effected (sic) with a public interest it ceases to be juris privati only*." The opinion described the conditions under which regulation is appropriate:

Property does become clothed with a public interest when used in a manner to make it of public consequence, and affect the community at large. When, therefore, one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use, and must submit to be controlled by the public for the common good, to the extent of the interest he has thus created. He may withdraw his grant by discontinuing the use; but, so long as he maintains the use, he must submit to the control.

The Supreme Court upheld Illinois' right to regulate the prices charged by grain elevators to the public. This decision reflects the belief that government regulation is sometimes necessary to protect the public good. The Austrian economist Joseph Schumpeter once described competition as "*the process of creative destruction*." It is the role of legislators and regulators to determine, with respect to the public interest, the potential impacts of competition's creative destruction and how it may affect such a vital service as electricity.

Regulators are creations of legislatures. When faced with a decision to regulate or not to regulate, the legislative decision is not necessarily a choice of opposites. Perhaps more appropriately such a choice should be viewed as a different means to accomplish common goals, the organization of society's business and the protection of the public good. This was eloquently stated by Lionel Robbins:

The invisible hand which guides men to promote ends which were no part of their intention is not the hand of some god or some natural agency independent of human effort; it is the hand of the lawgiver, the hand which withdraws from the sphere of the pursuit of self-interest those possibilities which do not harmonize with the public good.

Goals of Electric Regulation

Every action and every decision of a regulatory agency must consider the public's interest. The essential nature of electric service creates some of the dominant regulatory goals: an electric utility must serve all customers in its franchised service area; it must serve these customers without undue discrimination within the classes; the rates must be reasonable; the electric utility must have adequate facilities to provide reliable service to its customers both now and in the future; and the electric system must be operated in a manner that protects the environment.

The electric industry has developed, for the most part, under a system that has established monopoly franchises and used regulation as a substitute for competition. In recent years, actual competition has emerged in certain segments of the electric industry. Some believe that regulation of the electric industry is archaic and unnecessary, and that competition should be allowed to develop in all stages of the industry.

There are benefits that may be derived from a more competitive electric industry and the Commission should explore such options and change regulation where appropriate. The regulatory goals discussed above must be kept in mind, however. Competition should not be a goal in and of itself, although it may be a means of attaining a goal. The public interest is best served by the goal of an efficient, reliable, cost-effective, reasonably priced electric system that is environmentally sound. Concerned regulators and legislators are faced with determining how the reliable and environmentally sensitive electric system that has been achieved through historic regulation of the industry can be maintained and enhanced, while at the same time realizing and maximizing the possible economic benefits of increased competition.

B. Current Method of Electric Utility Regulation

The traditional form of electric utility regulation, commonly referred to as rate base regulation, rate-of-return ("ROR") regulation or cost-of-service regulation, was developed in the early 1900s after state regulatory agencies were created. This form of regulation was designed with a basic premise in mind -- an electric utility is a natural monopoly.

At the heart of ROR regulation is a concept known as the regulatory compact. In Virginia, as elsewhere, an electric utility is provided a monopoly franchise territory in which it is the only provider of retail electric service. Along with that franchise comes certain legal powers to enable the utility to provide service, such as the power of eminent domain. The utility is also provided with an opportunity to earn a reasonable return on the assets dedicated to its public service business. Such powers and opportunities are not granted without requirements. The other side of the regulatory compact is that an electric utility has an obligation to serve all customers in its franchised territory and it must provide adequate service at reasonable rates, as established by regulators.

Rate-of-return regulation and the obligation to serve were not designed for competitive markets. As stated in the order establishing this investigation, there is interest in using competitive market forces in the electric industry at both the wholesale and retail levels. The possible introduction of such competitive forces requires an examination of our current practices and procedures, an assessment of the possible future structure of the industry, and how our regulatory policies must evolve.

Rate Regulation

The fundamental difference between public utilities and unregulated businesses is that utilities have their rates (prices) set by a regulatory body. The regulation of rates has two aspects, setting the rate level and designing the rate structure. In setting the rate level, the Commission allows a utility to recoup all of its prudent operating expenses plus a reasonable return on its capital investment. In developing a rate structure, the Commission approves rates for various customer classes that are intended to be just and reasonable without undue discrimination within a class. Setting rate levels and designing rate structures are complex procedures that involve a time consuming process. Every policy or rule used in the process creates an incentive or disincentive to both the utility and the customer.

There are four basic steps of ROR regulation to determine the proper rate level, or revenue requirement, for a utility. First is determining the utility's gross revenues for the time period under review. Next is determining the allowable operating expenses, including taxes and depreciation, for the same time period. The third calculation is the dollar amount of utility assets used to provide electric service, known as the rate base. Finally a determination is made on the proper rate of return that should be applied to the rate base to reasonably and adequately compensate a utility's investors.

The first three elements of determining the revenue requirement involve accounting policies and techniques. A major responsibility of a regulatory commission is the prescription of accounting systems and the development of a representative cost of providing utility service for ratemaking purposes. As part of the ratemaking process, an extensive analysis is performed of a utility's revenues, expenses and investment during the test year and pro forma period. The results of this analysis quantify the proper recognition of a utility's operation and maintenance expenses, depreciation and income taxes, as well as establishes the investment or rate base upon which the utility is entitled to earn a fair return. This provides the financial basis from which the Commission may determine whether a change in rates is warranted.

Perhaps the most controversial regulatory accounting treatment is the use of deferrals. Electric utilities have historically incurred very large expenditures over long periods of time, for example the cost of constructing generating plants. It is also not unusual for a utility to incur an immediate extraordinary expense for something such as storm damage. For whatever reason the expenditures occur, regulators may want to spread a large expense over several years so current customers do not have sharply higher rates that must be lowered after recovery. With the use of deferred accounting, the expenses are written off over a period of years, with each year's write-off becoming part of that year's expenses.

The use of deferral accounting assumes utilities will remain a monopoly and that future customers can be required to pay the price necessary to provide the utility with the revenues needed to meet its obligations. In fact, regulation based on embedded costs provides assurances that prudently-incurred expenditures are likely to be recovered. Such assurances are incongruent with a competitive market. If customers can choose an electric supplier, they may choose to leave a utility that has high deferred costs.

A criticism of ROR regulation is that it does not create incentives for utilities to operate efficiently and keep costs down. For example, the concept of a return applied to the level of rate base may provide a disincentive to operate efficiently. The larger the rate base (assuming a similar rate of return), the greater the revenue requirement. Linking profits with capital investment provides an incentive for further investment and can lead to uneconomic expenditures. A utility executive recently stated that new furniture in his office should not create a need for higher rates. Such hyperbole can become reality if the subject is unneeded generating capacity instead of office furniture.

In determining a proper return for a utility, it is important that the utility maintain a strong credit standing in the financial community. The capital intensive nature of the electric industry requires the constant ability to attract additional capital. To maintain an adequate credit standing, the utility must be allowed the opportunity to achieve earnings comparable to companies having similar risk.

A first step in calculating an appropriate rate of return is examining the company's capital structure. Because of the nature of the regulatory process and the existence of franchised service territories, utilities have been viewed as having low business risk. Business risk is defined as volatility in earnings. Therefore, utilities have been able to finance their operations with a higher proportion of debt than most unregulated enterprises. For a company subject to volatile earnings, a debt ratio of 30% or less may be appropriate. Most electric utilities, which have historically experienced relatively low levels of earnings volatility, have debt ratios in excess of 50%. The ability of an electric utility to be highly leveraged, however, may diminish in a more competitive environment, due to less predictable earnings.

A company's cost of debt and cost of equity are analyzed separately. The cost of debt is rarely a controversial element in determining a rate of return. The appropriate return to be allowed on the equity component of the capital structure, however, is almost always a subject of debate in rate cases. Just as the relatively low business risk of the utility industry has historically allowed the use of extra leverage, the appropriate allowed return on equity for a regulated utility has been low compared to the potential return of an unregulated business. This is due, in part, to the comparable-risk/comparable-return standard and the low business risk of utilities. A more competitive electric industry will cause larger fluctuations in earnings, which translates into greater business risk. Unless there is a corresponding increase in a utility's equity ratio to offset higher business risk with lower financial risk, the utility should be allowed a higher return on equity.

Once the Commission has determined the appropriate revenue requirement by applying the authorized rate of return to the rate base, the attention shifts to the setting of rate levels, or rate design. The legal standards for appropriate rates are broad, as stated in §56-234 of the Virginia Code:

It shall be the duty of every public utility to furnish reasonably adequate service and facilities at reasonable and just rates to any person, firm or corporation along its lines desiring same. It shall be their duty to charge uniformly therefore all persons, corporations or municipal corporations using such service under like conditions.

The overall revenue requirement determination is structured to offer a fair return to a utility and its investors. Rate design is structured upon the development of revenue requirements for individual rate classes which reflect a number of objectives. Some of the principal objectives are rate stability, fairness, and avoidance of undue discrimination. Determinations of fairness and undue discrimination are generally based on the results of cost allocation studies, which attempt to separate the costs to the different customer classes according to the cause of the cost. The major customer classes are residential, commercial, and industrial.

There are three types of costs that must be recovered. First are the costs that change with the number of customers; these customer costs include billing, meter reading, accounting and service connections. Often, customer costs are combined with the second type of cost, the fixed or capacity costs. The fixed costs are associated with the utility's assets, consisting of plant and related facilities. These costs do not change with the amount of electricity that is produced and sold. The third type of cost is the variable cost, sometimes referred to as energy costs. As the name implies, variable costs fluctuate with usage levels. For example, the more electricity produced, the more fuel consumed.

The allocation of fixed costs is particularly difficult. Sometimes generating plants are sitting idle, but are required to be available to serve when needed. How much plant should be allocated to each customer class? This controversial decision is based, at least in part, on each customer group's maximum demand for capacity at a particular time. However, a substantial portion of fixed capacity costs is directly related to low variable energy costs. Therefore, it may be argued that these fixed costs should be allocated on the same basis as variable costs.

The allocation of variable costs is easier because they can be tied to a measure of product used by the customer, such as kilowatt-hours. A complicating factor is that variable costs differ according to the time of day or the season of the year. The largest variable cost is the cost of fuel, which can be as much as one-third of the total cost of electricity. A special mechanism which has been developed for the recovery of fuel costs is the fuel factor adjustment, which will be discussed later.

A prevailing objective in the setting of rates should be sending accurate price signals to customers that will result in economically efficient energy usage. Unfortunately, that has not always been the case. Most utilities and regulatory commissions have, in the past, attempted to protect residential customers from higher rates through rate class subsidies or the use of favorable allocation methodologies. These subsidies are provided through industrial and commercial rates that reflect a higher return component than the rates for residential customers. Commissions in general, and the Virginia Commission in particular, have attempted in the last several years to bring class rates of return toward parity. Even in the absence of outright competition, excessive rates could encourage large electric customers to leave a utility system through various means, such as closing a plant or through self-generation. Loss of load by the utility could adversely impact the utility or force the remaining customers to shoulder the share of the fixed cost contribution formerly allocated to the departing customers.

As mentioned previously, utility rate designs also seek to balance a number of objectives, such as simplicity, administrative ease, efficient use of utility services, and stability of rates, revenues and earnings. Deviations from the actual cost of providing service, for whatever reason, can lead to poor price signals, causing inefficient use of electric service. Inefficient use of electricity can result in a misallocation of resources, including the need for otherwise unnecessary generating and transmission investments.

Traditional regulation has also provided utilities an incentive to promote greater energy consumption because a utility's profits usually increase with higher sales. In most industries this is a logical and desirable tendency. However, as consumption of electricity increases, the need for generating capacity and transmission lines also increases. When the cost of new assets are higher than the average cost of existing assets, this causes rates to rise. In addition, increased consumption can lead to the depletion of natural resources and degradation of the environment.

Electric rate designs have historically provided customers with a limited number of service options. In addition, the Commission has been limited in the use of innovative rate proposals because all customers receiving service under similar conditions must be charged a non-discriminatory, uniform rate. Another statutory limitation is that significant rate design changes can only be made in rate cases. This sometimes creates a situation where appropriate rate design modifications are delayed because a company does not want to apply for rate relief. The situation is exacerbated by legislation that allows only one rate increase per year. Companies are reluctant to seek a rate design modification that causes a significant increase in a rate because that may preclude the company from filing for another increase for a year.

The process of rate regulation is time-consuming. It is common for over a year to pass from the time a utility files an application for a rate increase until the Commission order is released. The utilities are, however, allowed to place their proposed new rates into effect 150 days after filing (30 days after filing an expedited case), subject to refund if the full amount of the request is not granted. Utilities do not need approval for rate reductions. Historically regulatory lag has been frustrating, but acceptable when considered within the context of the regulatory compact. If increased competition develops in the electric industry utilities will need to be able to adjust their rates in a more timely manner.

Incentives For Generating Unit Performance

Since 1981, the SCC has administered an incentive program for electric utilities operating in Virginia, based upon the performance of a company's generating units. The potential reward or penalty is recognized in establishing revenue requirements based upon the proper return on equity for the company. The Commission sets a return-on-equity range of one percent (100 basis points) in a rate case; however, a specific point within that range must be used to determine the revenue requirement. For an electric company, that point is based upon its generating unit performance compared to industry averages. If a company has sustained superior performance, its return on equity will be set at or near the top of the range. Conversely, if an electric utility's generating performance has been poor, the Commission sets rates near the bottom of the range. An electric company's customers benefit from this incentive mechanism because generating unit performance has a large impact on the level of fuel expenses, which historically have been recovered from customers on a dollar-for-dollar basis. Therefore, the higher return earned through efficient generating performance is offset in rates by a lower fuel cost.

In a recent Virginia Power rate case, PUE920041, the Commission directed the Staff and other parties to explore the concept of expanding the incentive program to include purchased power contracts. Since the inception of the incentive program, purchased power has become a large component of the capacity resources of Virginia's electric utilities in general and especially of Virginia Power.

This review of the scope of the performance incentive program, just as the commencement of this electric restructuring investigation, recognizes that changes within the industry may require regulatory change. It is possible that performance incentives will become more comprehensive, and include more than purchased power contracts. On the other hand, some may argue that incentive programs are no longer necessary and that competition, or the threat of competition, may now provide all the incentives necessary for a utility to cut its costs, operate efficiently, and maintain reasonable rates.

Recovery of Fuel Expenses

In the 1970s, when fuel prices began to fluctuate wildly, state commissions developed mechanisms to protect electric utilities from drastic changes in fuel costs. It was believed that these mechanisms were needed to prevent utilities from having to constantly file for rate increases during a period of rising fuel prices and to protect the consumers from being overcharged during a period of declining fuel prices. The common mechanisms were fuel adjustment clauses, which could be recalculated monthly to reflect on bills an appropriate level of fuel expense, or fuel factors, which reflected projected fuel expenses for a period of time, usually a year, with a true-up at the end of the projection period.

Currently each of the investor-owned electric utilities in Virginia files annual fuel factor projections. The fuel factor hearings are separate from the base rate hearings previously discussed. It was considered appropriate to handle fuel expenses in a special manner because they were volatile, the price of fuel was not within the utilities' control and the fuel expenses were such a large component of the utilities' total expenses.

Unlike the filings for base rate changes, which use a historic test year, fuel factor filings involve projections for the upcoming year. Each filing also provides the opportunity to true-up any errors in the previous year's projections. Any prior period over-recovery or under-recovery of fuel expenses is included as a component in the development of a fuel factor. Each electric utility provides the Commission Staff monthly data used for monitoring the fuel usage and fuel prices for that month. If actual fuel usage or delivered fuel prices deviate significantly from projected usage, an interim adjustment to the fuel factor can be made.

Each customer's bill will contain a component reflecting the fuel factor established by the Commission. The utility is effectively granted a dollar-for-dollar recovery of its prudently incurred fuel expenses, but with no return.

While the fuel factor with its deferred accounting mechanism has proven a useful tool in maintaining the financial stability of Virginia's electric utilities during historic periods of exceptionally volatile fuel prices, it is time to reassess its value. There have always been valid concerns associated with the use of the fuel factor. First, the basic dollar for dollar recovery feature may provide inadequate incentive for the utility to minimize its fuel costs. Secondly, the examination of fuel expenses in isolation from other expenses may result in a failure to properly focus on total resource costs. Certainly, from a resource decision perspective, utility management may be distracted by the distinctively favorable recovery treatment of fuel costs as compared to that afforded costs of other resources. Finally, it is frequently argued that the use of a fuel factor type mechanism provides an incentive to maximize sales in the short-run. Additional sales will produce margins that increase profitability while the excess fuel costs associated with additional sales above the average system fuel cost will be deferred for recovery to the subsequent fuel year. Of course, efforts to increase sales may also increase peak loads leading to the earlier need for generation and transmission capacity additions which, if more costly than embedded plant, could lead to higher rates.

Additionally, the environment in which the fuel factor methodology was adopted has changed. Prices of coal, the most prevalent raw fuel source used in electric generation by Virginia utilities, have been fairly stable for many years, with actual price declines largely due to increased mining productivity. In general, both the coal-fired and nuclear generating units of Virginia's utilities (with the notable exception of Delmarva's Salem nuclear units) have achieved and sustained excellent operating availability. As would be expected, these factors have generally resulted in relatively small changes (frequently reductions) in annual fuel factors over recent years due to the reduced volatility of fuel expenses. In any event, new options should be explored for managing risk such as the developing futures markets.

More importantly, the increasing forces of competition in the industry are driving traditional regulatory accounting approaches such as fuel factors and accounting deferrals into obsolescence. Pricing in competitive markets is driven by current marginal costs, not accounting classifications of costs. New rate innovations, such as real-time pricing, appear to be moving toward the assignment of incremental or specific fuel costs to certain customer groups and away from the average fuel cost concept underlying the fuel factor. In addition to the complexity of administering differing customer group fuel cost assumptions, increased activity in the wholesale market is resulting in a growing significance of power purchases and sales along with the accompanying issue of what to include and exclude from fuel factor consideration. It is becoming extremely difficult to ensure that the fuel factor methodology provides the proper incentives to the utility and equitably balances benefits and costs among the utility and each customer group.

Regulation of Public Utilities Securities Issuances,

Affiliates Transactions and Asset Transfers

The SCC regulates the issuance of securities by public utilities under Chapter 3 of Title 56 of the Code of Virginia. All debt and equity issues must be approved in advance. The only exception is the issuance of short-term debt, which only requires approval if it exceeds 12% of total capitalization. Other transactions falling within the parameters of Chapter 3 include capital leases, loan guarantees by a utility to an affiliate, and joint and severally liable loan agreements. The Code specifically states the purposes for which securities may be issued. These purposes include the acquisition of property (including securities of other companies), construction or extension of facilities, improvement or maintenance of facilities, and refunding of debt.

Applications by utilities for approval of securities issuances are analyzed by Staff to determine the impact the proposed issue will have upon the company's capital structure and long-term capitalization goals. Staff examines the terms and conditions of the proposed securities in light of the current economic environment. In recognition of the importance of timing in the issuance of securities, the Code specifies a twenty-five day period to review such applications and issue an order.

The scrutiny of securities applications under Chapter 3 provides the Commission an opportunity to review the types of securities to be issued and the uses to which the capital will be applied before the proposed financing transaction takes place. Industry restructuring may cause conflicts with Chapter 3 authorities. For instance, if utilities begin to offer a wider variety of services, the use of capital secured by the issuance of securities may not be in accord with the purposes detailed in the Code. Another aspect of Chapter 3 that may come into play is that before a utility could restructure along functional lines by spinning off its generation assets (an alternative suggested by some to promote competition), it is likely that all of its current mortgage bonds will need to be refunded because of indenture requirements. This would require Commission approval of all new debt.

The Affiliates Act, contained in Chapter 4 of Title 56, provides that any contract or arrangement between a public utility and any affiliated interest is not valid unless approved by the SCC. The Act provides extensive authority to review before implementation the management, financial, service, and other contracts or arrangements between a public utility company and its parent or subsidiary. The same authority exists regarding any modifications or amendments to previously approved contracts. However, the fact that a contract was previously approved does not prevent Commission disallowance of any expenses for ratemaking purposes if they appear unreasonable. The Commission must also approve any loan of money or the assumption of any liability by the utility to any affiliate interest. In one of the strongest provisions of the Affiliates Act, the Commission has the authority to prohibit the payment of dividends by a utility if it is determined that the payment of the dividend could be detrimental to utility service. A primary purpose of the Act has been to protect the public interest by preventing self-dealing by the utility which could increase rates through excessive costs or weakened utility finances.

Within a restructured electric industry, the Affiliates Act may prove to be of great value to the Commission's mission of protecting the public interest. What is now generally a single, vertically integrated utility business may become a collection of regulated and unregulated businesses. Restructuring may necessitate the regulation of affiliate transactions on a broader scale in the future. As long as portions of the electric industry retain some form of monopoly power, the regulation of such transactions is critical. To the extent regulated and non-regulated operations are closely interwoven, effective regulation becomes more difficult.

Additional Commission authority is derived from the Utilities Transfer Act, Chapter 5 of Title 56. This Act provides that utilities must receive SCC approval before acquiring or disposing of certain utility assets situated within the Commonwealth. Approval is also required for a utility to acquire or dispose of the assets or securities of another public utility. The Transfer Act requires that a utility seek Commission approval before accomplishing any form of functional disaggregation of assets.

<u>Planning Reviews</u>

Long-range planning has been a critical component of the successful operation of an electric utility. Because of the long lead times needed to get necessary environmental and regulatory approvals and then to construct a generating facility, electric utility plans have covered a forecast period of fifteen to twenty years.

The obligation to serve has required that capacity be built or acquired according to forecasted customer demand levels. Unlike unregulated industries, electric utilities cannot choose to delay adding capacity because of economic conditions if that capacity is forecast to be needed; nor can utilities store the electricity for future use. As part of the regulatory compact, reasonable construction expenditures have been allowed into rate base.

Historically, electric utilities have included in their plans a high level of reliability. Reserve margins were set at levels that comfortably allowed for maintenance, unforeseen outages and weather anomalies. This conservative planning and emphasis upon reliability has been dictated by the obligation to serve the forecasted needs of customers and the strong incentives to maintain reliable service created by regulators.

The long range plans of electric utilities received increasing levels of scrutiny from regulators during the 1970s and 1980s. The common term for such forecasts became Integrated Resource Plans ("IRP"). These plans attempt to determine the change in demand over the forecast period, adjust that demand as effectively as possible through the use of conservation and load management, and show how the remaining level of demand would be met through capacity additions and/or purchases of power. The distinguishing feature of IRPs over previous utility forecasts is the integration of both demand side resources (conservation and load management) with supply side resources (capacity and purchased power) for meeting future loads.

For many years, Virginia's investor-owned electric companies have been required by statute to file ten year forecasts of their operations. In the mid-1980s, as utility planning became increasingly complex, the Commission began to study a more detailed and comprehensive planning process. This resulted in the development of an IRP process called a Twenty Year Resource Plan that the largest investor-owned companies are required to file. The first Twenty Year Resource Plans were filed in 1987, and they are filed every other year in the odd-numbered years. In the even-numbered years, an abbreviated Ten Year Forecast is required to keep the Commission updated on changes in expectations.

The Commission Staff reviews these plans in detail and compares them with the plans previously submitted by the Company. Staff examines the assumptions and expectations of all companies for reasonableness and discusses any concerns with the company. Staff prepares a report for the Commission summarizing the plans, pointing out important assumptions and changes, and detailing any concerns.

In Virginia, the filings are not subject to formal Commission approval, although in some states formal hearings are held on resource plans. Last year the Commission considered the adoption of a proposed federal standard relating to IRPs as required by the Energy Policy Act of 1992. One portion of the proposed standard was that IRPs "*must provide the opportunity for public participation and comment*...." There was some debate whether the opportunity for public participation required a formal hearing. In its order the Commission declined to adopt the federal standard while expressing its opinion that IRP is a "*vital, critical and necessary function of utility management*..." The Commission also stated that while there is a place for public comment in the planning process, formal hearings are not necessary. The Commission did mandate, however, that those investor-owned electric utilities required to file a Twenty Year Resource Plan solicit comments on the development of those plans from interested parties in informal discussions. These discussions should come early enough in the planning process so that any good suggestions can be analyzed and addressed in the final plan.

The next Twenty Year Resource Plan filings are due in the summer of 1997. The process of soliciting comments from the public will take place at the end of 1996 or beginning of 1997. The advantage of receiving input from other parties may be offset by an issue that will become increasingly contentious as competition develops. That issue is confidentiality of data. As previously mentioned, the current IRPs contain only a few pages that are considered confidential because of SEC regulations. As electric utilities enter competitive arenas, they will understandably be reluctant to divulge data related to their operations that may give competitors an advantage. Confidentiality concerns must be addressed by the next Twenty Year Resource Plan submission in 1997.

Another effect of competition on the planning process will be the length of the planning horizon. Utilities are already showing a reluctance to commit to capital expenditures until absolutely necessary. The historic ability to depend upon regulation to provide a reasonable return in the future is disappearing. A forecast twenty years in the future appears to have already become, to a significant degree, academic. Planning will still be an important process in the future, but planning requirements must provide utilities flexibility.

Bidding for Generating Capacity

In 1978, Congress passed the Public Utilities Regulatory Policies Act ("PURPA"). The intention of PURPA was to promote the efficient use of energy. One section of PURPA required utilities to accept offers of capacity from qualifying facilities ("QFs"). These qualifying facilities are predominately cogenerators -- facilities that generate electricity as a by-produce of the steam used for process heat in a manufacturing process. By comparison, traditional generating units vent the steam into the atmosphere. Another type of QF is the small power producer. These facilities use renewable forms of energy, particularly hydropower in Virginia. To receive QF status, a potential QF must file an application with the Federal Energy Regulatory Commission ("FERC").

Passage of PURPA did not initially have a great impact in Virginia or elsewhere. By 1986, only 123 megawatts ("MW") of new cogeneration and small power production had become operational on Virginia Power's system. About this time, however, potential cogenerators began to express a great deal of interest.

In Virginia, this interest was directed toward Virginia Power because it was the only electric utility in the state that projected a need for capacity. PURPA mandated that utilities pay QFs the equivalent of the utility's avoided cost, that is the cost that the utility could escape by not having to produce the electricity itself. There are two types of costs involved in the avoided cost calculation, the capacity cost and energy cost. The capacity cost is the cost associated with the construction of the generating facility, or the fixed expenses. The energy cost is the cost of fuel and other variable expenses. Therefore, if a utility did not have a need for new capacity in the near future, its avoided cost would only be the energy component. It would be very difficult for a project to be profitable if it were to receive only energy payments. Therefore, vendors hoping to build QFs focused their attention upon those utilities needing capacity.

Determining an appropriate avoided cost for a utility to pay QFs is an arduous process. In Virginia, a task force worked for more than a year to develop a methodology that was agreed upon by all parties. Even when using this methodology it was recognized that the actual setting of a rate could be tedious and open to conflict.

Another problem became evident when QFs came forward with an abundance of offers. Virginia Power's method of project-by-project negotiation with QFs became unworkable because QFs offered much more capacity than Virginia Power needed. It appeared ineffective to analyze and decide upon a project based upon the order in which offers were made. There was a need to evaluate the projects as a group.

These events convinced the Commission that action was needed to bring order into the resource solicitation process. In January 1988, the Commission issued an order that adopted a process which provides each electric utility in Virginia with the option of developing a bidding process for new generating capacity. All sources of available capacity may bid with one exception: neither the host utility nor any of its affiliates may submit a bid. If this were allowed it would require extensive Commission involvement in the evaluation to assure an unbiased selection.

Because each electric system has unique characteristics, the Commission decided to allow companies flexibility in designing their bidding programs within certain parameters. The role of the Commission and its Staff is not to manage utility planning, but to assure through proper oversight that companies conduct a thorough and unbiased evaluation.

Virginia Power currently has contracts for about 3,300 MWs of independent power, or about 19% of its total generating capacity. At one time, the Company had more non-utility generation than any other electric utility in the country. Competition in the area of construction of generating capacity turned out to be the crest of a wave of regulatory change in the electric industry. As one of the first states to allow competitive bidding, Virginia's approach was intended to bring order to the process and logic to the evaluation. Competition for the construction of incremental capacity makes sense theoretically, and pushed by PURPA it has become a reality. It must be noted, however, that while the competitive process produced more than a sufficient quantity of capacity for Virginia Power, we believe that the contracted costs of the associated power may be excessive.

Certificates of Public Convenience and Necessity

Generally, when an electric utility wishes to construct a generating facility or a transmission line of 150 kilovolts or more it must first receive a certificate from the Commission that the public convenience and necessity require such a facility. Generating facilities constructed by QFs have not been required to obtain a certificate of public convenience and necessity ("CPCN"). However, an independent power producer ("IPP") has been considered a utility under Virginia law and, therefore, has been required to apply for a CPCN just as any traditional electric utility.

In a CPCN hearing for generating capacity the debate usually centers around the need for the plant. Staff analyzes the utility's projections of demand growth and studies alternatives, such as conservation and load management. In addition to proving the need for the capacity, the applicant must show that the correct type of facility is being proposed; as such, the Staff examines the type of fuel to be used and operating characteristics. Also, the effect of the unit on the environment is an important issue.

Interestingly, the CPCN hearings for transmission lines are generally more contentious than those for capacity construction. When a generating unit is built there are usually a smaller number of people or businesses in the immediate vicinity of the plant as compared to a transmission route. Also, because a generating unit brings both employment and tax revenues into the locality, the benefits of the plant often exceed any negative aspects. For a transmission line, however, many people may be affected along the path of the line, there are no long-term employment benefits, tax benefits are minimal, and there may be an impact on property values. The major issues in transmission line hearings are the need, the right of way, health concerns, environmental effects, and aesthetic impacts.

The CPCN process for both capacity and transmission line construction may be affected by increased competition in the electric industry. In theory at least, the need for capacity in a competitive environment would be determined by the market, not a utility's forecast of demand. Last year, the Commission turned down an application by Patowmack Power Partners to construct an independent generating unit that would sell electricity on the spot market. The project was rejected because there was no demonstration of need for the plant to provide just and reasonable service to Virginia ratepayers.

Disputes between federal and state regulators may arise regarding the construction of transmission lines.

FERC has responsibility for wholesale sales and interstate transmission of power. The states have maintained the responsibilities of siting and approving transmission line construction within their boundaries. The free-flowing transfers of power that may become a part of the electric industry of the future may require additional transmission lines, particularly in some of the highly populated areas in the East. State commissions may not be willing to approve controversial new transmission lines through their jurisdiction, especially if substantial local benefits are not evident.

Demand Side Management

Demand side management ("DSM") activities attempt to change the consumption patterns of electricity. There are two primary types of DSM: conservation programs and load management programs.

Conservation efforts are aimed at reducing energy usage and, hence, conserving natural resources and reducing pollution since less power is generated. Load management programs shift energy usage away from the daily peak, or heavy usage time, to the off-peak. Therefore, load management programs are not intended to directly impact energy usage or to conserve natural resources or lower pollution levels, but they are valuable to utilities and their ratepayers because they allow a more efficient use of the system and reduce the capital needed for capacity additions.

In March 1992, the Commission issued an order in an investigation into the conservation and load management ("CLM") programs of both electric and gas utilities. In that order, the Commission stated "*cost effective CLM programs are essential components of the balanced resource portfolio that utilities must achieve to provide energy to Virginia customers at fair and reasonable rates*." It also stated that "*while we are encouraged about the role conservation can play in our future, we must move cautiously in an attempt to avoid promoting uneconomic programs, or those that are primarily designed to promote growth of load or market share without serving the public interest. Conservation at any cost is not appropriate*...."

The Commission's encouragement of DSM but insistence on cost effectiveness set the tone for related policy decisions. During the 1980s, the regulatory treatment of DSM, particularly conservation, caused courtroom battles in commissions throughout the country. There was a wide variety of responses. Some commissions mandated that utilities make certain levels of commitment to DSM based upon a percentage of revenues, an absolute dollar amount, or some other benchmark. Some commissions allowed a cost/benefit analysis, which added to the benefit side of the equation a quantification in dollars of certain societal benefits, such as pollution abatement.

The Virginia Commission's approach was conservative. There was a concern that some DSM programs, particularly conservation programs, created winners and losers. For instance, if there was a rebate program for an energy efficiency measure, the customers that participated in the program would receive a benefit and their energy usage would decline. The remaining customers would have to pay for the rebate as well as the portion of the fixed cost that the participating customer would avoid with reduced usage.

The Commission clearly stated that it would not attempt to quantify societal benefits in the cost/benefit analysis. There are many types of societal costs and societal benefits involved with DSM, but the major ones are environmental. Some environmental costs are already considered by a utility and factored into its cost of service. For instance, the cost of compliance with the Clean Air Act is already being included in the overall expense of a fossil fuel plant. Societal costs are those that are external to the existing process. For instance, it has been argued that even plants that meet all federal and state pollution standards are emitting pollutants and using natural resources and there should be a cost assigned to such environmental impact.

The Commission considers external environmental factors from a qualitative standpoint, particularly in construction approval applications. Further, it appears the Commission lacks the statutory authority to quantify such costs. Virginia Code § 56-235.1, which deals with the conservation of energy and capital resources, instructs the Commission that "*nothing in this section shall be construed to authorize the adoption of any rate or charge which is clearly not cost-based*..." Also, Virginia Code § 56-235.2 states that the utility must demonstrate that its "*rates, tolls, charges or schedules in the aggregate provide revenues not in excess of the aggregate actual costs incurred*..."

The Commission's order in PUE900070 included revised promotional allowance rules that establish the conditions under which electric and gas companies may propose to recover in rates the cost of promotional allowances to customers. Even if the utility does not intend to recover promotional costs in rates, and instead will pass the cost on to stockholders, the promotional activity may be prohibited if the Commission determines that it is adverse to the public interest.

Most of the DSM programs that have been approved in Virginia are experimental programs. These programs allow the utilities to test proposals on a limited number of customers with a limited amount of capital. Using results from the experiment, the company can request permission to make the program permanent. There are a variety of programs being tested, from conservation to load management, and involving different forms of incentives, from rebates to low cost financing.

It appears the Commission's conservative approach to encouraging DSM has proven wise. Recently, due to high electric rates and the threat of increased competition in the electric industry, some state commissions that took a more aggressive approach to promoting DSM by mandating broad and expensive programs have begun to recant. With competition the market price of electricity becomes all-important. If DSM programs cause a utility's rates to rise, it creates an incentive for customers to seek alternatives and makes it harder for that utility to compete.

Social Objectives

Utility regulation is, for the most part, economic regulation. There are evident pressures, however, for both social and political objectives to be accomplished through the regulatory process. This will likely change with increased competition.

Traditional regulation has provided many social benefits, including reliability of service, research and development, investment in conservation and renewables, ubiquitous service, and stability of rates. Can these societal benefits be achieved while recognizing the benefits of competition? Subsidies from one class to another will likely come under intense pressure with competition. This may be positive if economic efficiency is enhanced by the elimination of subsidies and results in improved functional price signals. However, rate averaging among classes has provided price certainty and revenue stability. These benefits may be lost with increased competition. The impact may be detrimental particularly to rural customers for whom the cost of being connected to the electric system may be significantly more expensive.

The perception that utilities have largely unlimited resources and the ability to pass costs on to ratepayers, a deep pockets mentality, has precipitated most of the historical political pressures on the industry. These perceptions can result in targeting utilities for selective taxation or for funding certain causes such as economic development or environmental programs. An example of this is the Clean Air Act Amendments of 1990 in which Congress largely focused on utilities rather than other sources of pollution, such as automobiles. Utilities were an obvious target. Cleaning up the emissions from a large generating unit could achieve the same effect as reducing the emissions from thousands of automobiles, therefore, utilities and their ratepayers were made responsible for billions of dollars of investment necessary to implement Clean Air Act requirements.

A spirited debate could be staged as to whether social and political objectives should have ever been considered in the electric industry. The fact is that they have been, and in the future such consideration may be impossible.

Regulatory Philosophy

The Virginia Commission does not attempt to micromanage the electric utilities it regulates. To the contrary, the Commission gives utilities a great deal of operational latitude to manage their business and fulfill their public service obligations, with appropriate Commission oversight. The primary objective of the Commission's authority and responsibility is the protection of the public interest, specifically in the provision of reliable electric service at just and reasonable rates.

The Commission must serve many constituencies. The residential, commercial and industrial users and utility investors must be considered, of course, and their interests are not always the same. Also to be recognized are the views of environmental groups, localities, economic development officials, apartment owners, government agencies and energy services companies. The Commission cannot favor special interest groups but must consider the Commonwealth's overall public interest.

The electric industry is changing. The Commission and the General Assembly need to respond to change and, if appropriate, amend statutes and adjust policies in response to the changing environment. As long as there is a vestige of monopoly power within the industry, however, protection of the public interest must be paramount. Increased competition may offer many benefits, but can the public continue to be protected in circumstances where free markets may not provide sufficient discipline? That is a primary focus of this study.

C. Events That Have Shaped The Electric Industry

Beginning in the mid-1960s, a series of events occurred that in combination have created the impetus to restructure the electric industry. For several decades the industry had thrived financially in relative tranquillity. Especially for a period of time after World War II, the business of producing electricity was in its prime. As the economy surged, electricity became the power resource of choice. The price of electricity declined due to economies of scale and innovative technological efficiencies associated with large, new power plants. Electricity usage grew faster than energy usage as a whole; more and more capital was raised to build generating plants and transmission lines in order to serve the burgeoning demand.

A Confluence of Circumstances

Electric utility companies' balance sheets were strongest and rates lowest at about the time the U.S. was entering the Vietnam War. In November 1965, an event occurred that dramatically demonstrated vulnerabilities in our electric system. An equipment failure at a Canadian utility that was interconnected with U.S. utilities caused a collapse of power pools throughout the Northeast.

For years, the electric industry seemed invincible. The Northeast Blackout forced a reassessment of the reliability of the system. It appeared that transmission interconnections needed to be reinforced to prevent future blackouts. Reserve margins had reached low levels in many systems, signaling a reduction in reliability. Therefore, capital expenditures began to increase for assets that would not lower the price of electricity, but would enhance system reliability.

Utility expenditures increased on another front during this time period. With the passage of the National Environmental Policy Act of 1969, the federal government established policies for environmental protection. Following passage of this Act, a number of new statutes and amendments to existing statutes were enacted. Many of these affected utility plants and transmission lines. Not only did the cost of these assets increase, but their siting and licensing processes became more costly and lengthy. None of these expenditures increased the efficiency of units or lowered costs to customers.

In addition, the increasing benefits from the economies of scale that were enjoyed during the 1940s and 1950s had leveled off. New plants were not significantly more efficient than their predecessors and the associated cost savings could no longer be attained through construction of larger units. In an attempt to garner increased efficiencies, the industry lunged into the nuclear age, seeking electricity at a cost characterized as "*too cheap to meter*."

The Energy Crisis

The effects of the Northeast Blackout and environmental regulations were just a tremor to the electric industry compared to the earthquake of the Arab oil embargo of 1973-74. The price of oil, and correspondingly all forms of energy, increased rapidly. Americans reevaluated their use of energy. Long lines at the gas pump were a common scene. In 1974, the sales of electricity dropped for the first time since World War II.

The electric industry had grown accustomed to a continual increase in demand. Utility forecasters at the time were portrayed as merely using a ruler to draw an upward line of future demand growth. Many utilities, including Virginia Power, had committed to large construction projects, often nuclear, to meet the expected surge of demand. Not only did many of these large capital projects become a financial albatross, the industry's revenues were not growing like before due to rising prices and a sluggish economy. As would become evident by the end of the 1970s, the electric industry was slow to react to the pressures of declining sales and increasing capital costs. The financial condition of utilities deteriorated significantly.

Rate increases became more frequent during the 1970s, often outpacing the growth in inflation. The public's confidence in the electric utility industry weakened. Utility commissions throughout the country were overwhelmed with an increased work load and issues of mounting complexity. Commission staffs were enlarged. Hearings became lengthy, often expensive, and increasingly antagonistic.

Three Mile Island

On March 28, 1979, a malfunction at the Three Mile Island nuclear plant caused panic in the area and shattered America's faith in the nuclear power industry. The accident could not have happened at a worse time. The effects of the Arab Oil Embargo upon the cost of fossil fuel had stimulated the growth of nuclear power, which was envisioned as a means of reducing reliance upon foreign oil. The price of constructing nuclear plants had already proved to be a strain upon utilities' capital. Now the safety of the plants had been brought into question and the implications of a serious nuclear accident were terrifying.

During this period, the electric industry was in turmoil. From the time of the Three Mile Island incident no new nuclear plants were ordered to be built in the U.S. Many of the plants that had been ordered or were under construction at the time were never completed. These canceled nuclear plants and their associated costs triggered a round of prudence hearings before public service commissions that raised questions about the ability of electric utilities to plan and increased the risk of regulatory disallowance of expenses.

Traditional regulation of utilities required electric companies to demonstrate that assets such as generating plants were "*used and useful*" before the costs of the asset were allowed in rate base and recovered from customers. Prudence reviews focused upon the used and useful concept, including the need and financial desirability of the investment, as well as the wisdom of the utility management's investment decisions.

Prudence hearings during the 1980s provided a wake-up call to the electric industry that full reimbursement of investments was not a certainty. The fear of cost disallowance led many utilities to avoid building generating capacity and helped lay the groundwork for the emergence of non-utility generators. This change in philosophy accelerated the move toward restructuring that we have today.

PURPA and EPAct

The Public Utilities Regulatory Policies Act ("PURPA") was enacted by Congress in 1978 to promote energy efficiency and to reduce dependence from foreign fuel sources. The effect of PURPA was to increase the interest in self-generation, co-generation and independent power.

PURPA established a class of non-utility generators ("NUGs") called qualifying facilities ("QFs") whose electric output was required to be purchased by utilities. At first, most electric utilities were against PURPA and the development of QFs. However, the legal requirement coupled with the reluctance of utilities to build capacity during the period of high inflation and regulatory disallowances opened the door for QFs to thrive, with an increasing supply of new capacity being built by NUGs. Ironically, high cost QF contracts that were signed based on inaccurately determined avoided costs now haunt many utilities as a main component of their potential stranded cost under a competitive industry structure.

The Energy Policy Act of 1992 ("EPAct") further accelerated non-utility power production by creating a new category of power generators, the exempt wholesale generator ("EWG"). Before EPAct, NUGs that were not QFs had to create complicated corporate structures to avoid becoming subject to the Public Utility Holding Company Act of 1935 ("PUHCA"). The EPAct amended PUHCA to exempt NUGs whose only business is owning generating facilities that sell electricity in the wholesale market. Therefore, EWGs have the same exemption from PUHCA that QFs have had since 1978, except EWGs do not have to meet the operating requirements and size constraints imposed upon QFs and utilities do not have an obligation to purchase the EWGs' output. The EPAct also made it easier for utility subsidiaries to participate in the NUG market. In the U.S. electric industry, more new capacity has been brought on-line since 1989 by NUGs than by traditional utilities. Much of this capacity is owned by non-regulated affiliates of electric utilities.

A change enacted in EPAct with respect to transmission access has significant implications for increased competition at the wholesale level. Prior to EPAct, utilities were able to deny NUGs access to their transmission lines which were needed to sell power to any entity other than the local utility. Therefore, ownership of the grid meant control of grid access and, hence, monopoly power. With EPAct, FERC now has the authority to order access to transmission lines at a FERC-approved rate. Therefore, NUGs now have increased ability to sell power in the wholesale market.

Under EPAct, if an entity requests wheeling service from a utility, the utility must either agree to provide the requested service or provide a written explanation of why it will not provide the service. The explanation must include the proposed rates, charges, terms and conditions by which it will provide transmission and its analysis of any constraints affecting the provision of transmission service.

An entity may file an application with FERC requesting an order requiring a utility to provide transmission services to the applicant. After a hearing, FERC will issue a draft order and set a reasonable time for the parties to agree to certain terms and conditions. If the parties fail to agree or if FERC disapproves of the agreement, FERC will prescribe the terms and conditions in its final order. FERC can issue a wheeling order if it is in the public interest and would not "*unreasonably impair the continued reliability of electric systems affected by the order*." However, FERC cannot issue an order that requires retail wheeling. Also, any FERC order requiring wholesale transmission must include rates which allow the transmitting utility to recover all costs associated with the transmission services, including a share of "*legitimate, verifiable, and economic costs*." These costs, often referred to as stranded costs, must be recovered from the entity receiving wheeled power, not from the utility's existing customers.

In March 1995, FERC issued a notice of proposed rulemaking in which it proposed requiring all electric utilities to file open access transmission tariffs. A final order in that case was issued by FERC on April 24, 1996. That order will be discussed in the next chapter.

These recent changes in federal law have opened the wholesale market for electricity to a greater extent, and they have also contributed to a growing clamor from various parties for further revisions in both federal and state regulatory policies. The jurisdictional boundary between federal and state regulation is becoming less clear and with such indistinction inevitably comes conflict.

State Versus Federal Jurisdiction

Section 201 of the Federal Power Act ("FPA") grants FERC jurisdiction over the transmission of electricity in interstate commerce and the sale of electricity at wholesale in interstate commerce. States have long-standing jurisdiction over the retail sales of electricity, which have comprised the majority of utility revenues. The FPA preserves traditional state regulation by limiting FERC's jurisdiction to "*only those matters which are not subject to regulation by the States*." States also have long exercised authority over the planning, siting and construction of generation, transmission and distribution facilities. For years, the FPA seemed to draw a "*bright line*" between federal and state jurisdiction over electricity. The industry's recent transition, the EPAct, and FERC's assertion of jurisdiction over certain issues have blurred the previously clear line.

Transmission lines were constructed primarily to serve a utility's own customers, sometimes referred to as native load customers. As the electric system developed, transmission systems of adjoining utilities were interconnected to increase reliability and allow economy power sales and purchases between utilities. The pervasiveness of the interconnected electric grid has led FERC to the conclusion that transactions using the grid, even if wholly intrastate, are actually interstate transactions and are subject to FERC's exclusive jurisdiction. In 1964, the U.S. Supreme Court upheld FERC's jurisdiction over intrastate wholesale sales, in part based on the fact that some electrons in the transaction may have been generated out of state.

The debate over FERC's jurisdiction has become more significant in recent years. With the rise of independent power production, wholesale purchases have become more prevalent. State commissions have fought to maintain jurisdiction over wholesale transactions insofar as they affect retail rates. Conflict has arisen over whether state commissions can limit the pass-through in retail rates of costs which arise from FERC approved wholesale transactions. In 1977, the Rhode Island Supreme Court in *Narragansett Electric Co. V. Burke* found that its state commission did not have the jurisdiction to rule on the reasonableness of a FERC-approved rate in a wholesale transaction. The U.S. Supreme Court declined to hear the appeal, but has supported the decision in other cases.

In 1983, the Pennsylvania Commonwealth Court ruled in *Pike County Light and Power Co. v. Pennsylvania PUC* that its state commission did have authority to determine the prudence of a utility's decision to enter into a wholesale transaction. If a state commission determines that a better, less expensive option was available to the purchasing utility, then rate recovery of FERC-approved costs can be denied. The FERC-approved rate is not questioned by the state commission, but rather the purchasing utility's decision to enter into the transaction is put at issue.

The *Pike County* rule does not appear applicable where FERC's approval of an interaffiliate wholesale transaction allocates costs among affiliates. Two Supreme Court cases have addressed this issue: *Nantahala Power & Light Company v. Thornburg and Mississippi Power & Light Company V. Mississippi ex rel. Moore.* In both cases, the Court found that FERC's approval of a wholesale transaction between utility affiliates barred the state from setting retail rates as if a transaction more favorable to the purchasing utility had occurred.

The EPAct gave FERC authority to mandate access to transmission and, under certain conditions, requires utilities to enlarge their transmission facilities. However, states still have the authority to review transmission proposals for siting and environmental permits. Therefore, a FERC order requiring construction of a transmission line may be stalled at the state level. Since the transmission system is used for both retail and wholesale transactions, the potential for stalemate exists unless there is cooperation between federal and state regulatory agencies.

FERC has proposed the development of regional transmission groups ("RTGs") to resolve conflicts between state and federal agencies and overcome barriers to an open access transmission system. The RTGs would be boards composed of state commission representatives from each state within a defined region. The FPA grants FERC authority to refer issues to such a joint board which may be vested with the same powers as FERC to hold hearings and issue orders. Conceptually RTGs make sense, but there is a possibility that each state would pursue its own goals rather than regional goals and consensus on issues could be challenging.

D. Comparison With Other Restructured Industries

There are other industries that have recently been deregulated and, where possible, lessons should be learned to help in the transition of the electric industry to more competition. The natural gas, long-distance telephone and airline industries appear to have similarities with the electric industry. These industries are capital intensive, exhibit certain economies of scale, and deliver a product or service that is dependent upon a developed infrastructure. Each industry also has undergone a change from heavy regulation to greater competition and more relaxed regulation within the last twenty years.

Natural Gas Industry

The natural gas industry is often touted as the polestar for electric deregulation, especially since both are energy industries. The deregulation of the natural gas industry has been successful in many ways, particularly in the removal of government controlled prices of natural gas. Prior to restructuring, the natural gas industry relied very heavily on regulation of price and service with little use of market forces. Interstate pipeline companies were the exclusive aggregators and suppliers of gas (usually purchased under long-term contracts with producers) to local distribution companies ("LDCs"). LDCs, in turn were the sole providers of bundled gas service to customers.

Because the price of gas was regulated, with little relation to supply or demand, a shortage developed, sending pipelines scurrying to secure long-term supplies at escalating prices. When the price forecasts of the oil embargo era failed to materialize, pipelines were left with a massive take-or-pay liability for gas they had committed to buy at high prices which could not be resold except at much lower rates.

During this same time frame, LDCs and industrial customers sought access to pipeline capacity. Under industry restructuring, they could purchase gas directly from producers at much lower prices than available from the pipelines and purchase transportation service from the pipelines for delivery. LDCs also began to offer transportation service on their distribution systems to enable end-users to transport gas purchased elsewhere. As LDCs and industrial customers secured their own gas supplies, the take-or-pay liability of pipelines increased. The price of natural gas, long subject to federal control, was deregulated in stages under the Natural Gas Policy Act of 1978 ("NGPA").

The restructuring of the natural gas industry also involved a significant stranded cost issue. The take-or-pay issue was addressed in a number of ways. Pipelines and producers renegotiated contracts, and FERC required pipelines in certain circumstances to absorb a portion of the liability. Former pipeline sales customers, who had turned to transportation, were also required to pay a transition charge. Pipelines ultimately were required to unbundle services and separate their merchant function into a separate business from the pipeline business. Stranded costs were composed of long-term contracts between pipeline companies and producers that were priced higher than the new, competitive market price. Liability was addressed through negotiations with producers, recovery from customers, litigation, losses to shareholders, and, in one case, bankruptcy.

The restructuring of the natural gas industry was furthered in the mid-1980s by a series of FERC orders at a time when there was an excess supply of gas. That fact caused buyers of gas to depend upon the spot market for purchases. As supply and demand came into balance, purchasers became less reluctant to sign longer term contracts. A viable futures market has now evolved, particularly for hedging and structuring financial deals.

Natural gas prices have declined, for the most part, since passage of the NGPA, and consumption has increased. These price declines are attributable to increased competition at the wellhead and technical advances in the location and development of gas reserves. LDCs and large end-users have taken advantage of this competition, with LDCs able to secure lower gas prices for their customers and large end-users able to purchase their own supplies. Although some large customers have been able to bypass the local distribution company to access lower priced natural gas, a similar opportunity has not yet developed for most residential customers. Because of the relatively low usage of an individual residential customer, it will be necessary for a marketer to aggregate residential load in an area and arrange an alternative supply of gas -- i.e., to replace the LDC as the supplier of gas. That has not happened in Virginia and has only recently begun to be addressed in some other jurisdictions. The aggregation of residential natural gas customers should be less complex than the aggregation of residential electric customers since the flow of gas can be more easily controlled and gas can be stored. The time lag in the development of a competitive residential gas market raises the question of how long it would take a competitive electric industry to reach residential users with individual choices of suppliers.

While there are a number of similarities, such as the provision of transportation service (transmission) and take-or-pay (stranded costs), there are differences between the electric and natural gas industries that must qualify any predictions about electric industry restructuring based on observation of natural gas restructuring. A major issue in the restructuring of the electric industry is whether it will be sufficient to separate generation from transmission and distribution on a functional basis, or if generation divestiture will be necessary in order to develop a competitive market. The natural gas industry, unlike the vertically integrated electric industry, evolved with separate companies performing the functions of production, transmission and distribution. This not only provided a more amenable structure for deregulation, but also made the stranded cost issue easier to address because stranded costs were more identifiable and there were more entities able to absorb a portion of the liability.

There are more barriers to entry in the electric industry compared to natural gas. The capital cost to provide electric service is higher and there are more stringent environmental requirements. Greater planning is required for an electric system since it has several forms of generating units -- base-load to peaking -- and various fuels to run the units. The natural gas industry basically deals only with the delivery of a fuel product through a pipeline infrastructure.

There are many operational characteristics of the electric industry that distinguish it from the natural gas industry. While you can't effectively store electricity, the storage of natural gas is common and relatively uncomplicated. The availability of storage causes the price of gas to vary less than electricity. Electric costs can vary widely during the course of a day; natural gas prices generally are quoted on a daily basis. Also, there are substitute methods of delivery for natural gas, for instance, liquefied natural gas which can be transported by barge, truck or rail. Unlike electricity flowing through transmission lines, the flow of gas in a pipeline can be readily controlled. Also problems can easily be isolated on a gas line. In general, the restructuring of the natural gas industry was not as complex as a similar restructuring of the electric industry would likely be, which qualifies lessons to be learned from the natural gas industry experience.

Long-Distance Telecommunications Industry

In the telecommunications industry, local telephone service is beginning to encounter competition, especially with the passage of the Telecommunications Act of 1996. Local exchange competition is too new for lessons to be learned and applied to the electric industry. However, there have been competitors in the long-distance telecommunications market for more than a decade, with competition becoming especially intense after the breakup of AT&T in 1984.

The Virginia Commission was one of the first state regulatory bodies to detariff AT & T's intrastate long-distance market, thereby encouraging competition. Starting with that 1984 order the Commission Staff has monitored the competitive activity in Virginia's intrastate long-distance market on a quarterly basis by gathering information from the certificated competitors and calculating market shares using different measures, such as revenues and number of calls. At divestiture, AT&T had a share of the Virginia market well in excess of 90%. That share has now declined to approximately 60%. Apparently, a similar trend has developed throughout the U.S.

The competition that has developed in the long-distance telephone market has been dominated by AT&T, MCI and Sprint. However, smaller firms have been able to carve out niche markets. The smaller competitors generally lease capacity from one of the three large companies at a discount and then resell that capacity. This resale capability has removed a barrier to entry to the long- distance market since it would not be cost effective for each company to install its own nationwide transmission system.

Contrary to advertising campaigns of the major competitors, competition in the long-distance market has not resulted in significant differences in price among the big three firms. The quality of service is also similar. The firms have competed mostly on various discount plans and extra services. Determining which company may be best suited for an individual's calling pattern can be very confusing and complex.

For the most part, deregulation of the long-distance market has been successful. There are a range of choices for consumers and the price of long- distance calls has declined since 1984 for those customers that use a discount plan. It will be difficult to base electric utility restructuring upon the telecommunications experience, however, because the two industries are dissimilar in several ways.

Technology has been the driving force behind the telecommunications industry restructuring. If there is a telecommunications equivalent to a generating unit it would be a switching system, which is basically a computer. As with other computer technologies, switching systems have drastically decreased in size and price while dramatically increasing in capabilities. The telephone equipment used by customers has also improved, from answering machines to cellular phones to fax machines. New services seem to be introduced every day. In the electric industry there have been some technological advancements; however, they are nowhere near as numerous or far-reaching as those in telecommunications.

There is an abundance of transmission capacity in the long-distance network. Fiber optic lines criss-cross the nation, with each strand providing an amazing amount of capacity. In addition, microwave transmission towers and satellite systems can carry voice and data transmissions through the air.

In the electric industry, transmission capacity is limited. There are particularly critical transmission interconnections that are fully loaded many hours of the year. Also a delicate balance must be maintained between the generation and transmission of electricity. There are no techniques to transport electricity without the use of wires, as in microwave or satellite transmissions of voice and data.

As mentioned earlier, competition in the local exchange telephone market is just starting; it is too early to draw any conclusions. There is, however, a developing concern related to the local exchange companies' ("LECs") preparation for competition. The once exemplary service of some LECs has recently become tarnished. For instance, in Wisconsin, service complaints against Ameritech nearly doubled in 1995. The Wisconsin Public Service Commission filed a civil suit against Ameritech over low-quality and unreliable service. In particular, the most common complaints in Wisconsin and elsewhere have been long waits for repairs or phone installations and the inability to reach a live person in the service center.

The cause for a reduction in service quality seems evident. There has been a surge in new lines for new services such as fax machines, coupled with large numbers of workers being laid off in an attempt to cut costs. Some suggest that "*gold-plated service, which phone customers took for granted back in the era of local monopolies, is gone forever -- and people had just better get used to it*." With the wave of cost-cutting now sweeping the electric industry, quality of service will have to be monitored with renewed emphasis.

Airline Industry

Although the airline industry has not been considered a utility, it was once heavily regulated and it has some characteristics similar to the electric industry. For instance, both industries are capital intensive. They depend upon a network of infrastructure, although the airlines' infrastructure, airports and the air traffic control system, is owned by the government rather than private corporations. Also, just as electricity can't be stored, the number of seats available for a particular flight is limited to the plane assigned for that flight.

Before 1978, the maximum and minimum fares that could be charged by airlines and the routes they could serve were established by the Civil Aeronautics Board. The Airline Deregulation Act of 1978 deregulated fares and removed barriers to entry for routes. The results have been mixed and the industry has been chaotic.

Some airline fares today are much lower than in 1978. In particular, vacation travelers flying long distances that are able to order tickets well in advance and fly at nonpeak times often receive deep discounts. These reduced fares have helped airline travel surge. Interestingly the larger users, business travelers that often fly shorter and less heavily traveled routes, often must pay higher fares than the vacation traveler.

Under regulation, weak or poorly managed airlines could practically be assured of survival. Now airlines go out of business and new airlines are formed seemingly on a daily basis. Under regulation, small cities could be guaranteed service. Now, some smaller cities have no service or limited service, depending upon the number of potential passengers.

The early predictions that a deregulated airline industry would be dominated by a few strong companies did not come true. In fact, the number of U.S. airlines grew from 36 in 1978 to 123 by 1984. Some of the weaker airlines went out of business in the late 1980s, leaving behind many planes and personnel available at reduced prices and salaries. This triggered another recent round of start-up airlines.

Today, several of the new airlines are bankrupt and most major airlines have endured several years of losses. Some airlines have cut service and restructured their operations. Orders for new planes are at a low level. The new trend among airlines is forming voluntary alliances to share routes and passengers.

A large difference between the airline and electric utility industries is the value of the service provided by each. Although some airline passengers may yearn for a return to the stability of a regulated airline industry, many prefer the cheap seats that are available as a result of deregulation. They believe the savings are worth dealing with crowded airports, packed flights and occasional cancellations.

Customers will not likely be as flexible with their electric service as with airline service. In the U.S., users are accustomed to a high degree of reliability in their electric service. It would take a significant savings for most customers to accept a reduced amount of reliability. An unsettled industry with companies coming in and going out of business would cause more concern in the electric industry than in the airline industry.

<u>Summary</u>

The natural gas, long-distance telephone and airline industries have all gone through phases of deregulation with mixed but overall positive results. The electric industry, however, has unique characteristics, and the successes and failures of other industry restructurings provide only limited guidance for electric industry restructuring.

III. THE STIMULUS FOR RESTRUCTURING

Many electric industry participants advocate restructuring the wholesale and retail electric markets. The push for restructuring has gained momentum over the last few years. This chapter will explore some of the factors that have prompted the call for restructuring and will discuss recent actions of federal and state regulators, legislators, and utilities regarding industry change.

This chapter begins with a discussion of the benefits that a competitive electric market may bring, and a few caveats as well. Also discussed are certain international electric markets that have undergone deregulation and are often cited as models for change in the U.S. Some of the characteristics of the current U.S. electric industry that have given momentum to restructuring are examined, such as technological advancements, excess capacity and regional price differences. A recent FERC order that promotes wholesale competition is summarized. Next is a synopsis of federal legislative proposals that will have a dramatic effect upon the electric industry if passed. There is also a review of developments in the futures market for electricity, regulatory changes in some states and reengineering being conducted by some utilities -- all reactions to the push for increased competition.

A. The Potentials of Competition

The current momentum to restructure the electric industry is fostered by the recognition that, where feasible, allowing market forces to control an industry is more effective than government regulation. America's economic structure is based upon the free market system.

The general consensus is that the movement toward competitive markets in most industries has been positive and has produced benefits for the public. A significant caveat is that, in order to attain the benefits of competition, an open, reasonably (or workably) competitive market must exist or develop. If no competitive market develops, firms may abuse their market forever. Promoting competitive markets requires more than eliminating regulation and allowing firms to operate without constraint. The key to restructuring and to developing effective competition is, therefore, market structure.

Political

There are some political arguments in favor of competition. Because competition requires many buyers and sellers, market power is decentralized and dispersed. No single buyer or seller controls the market. Supply and demand determine resource allocation and income distribution, monopolists and government do not. As one writer stated:

Limiting the power of both government bodies and private individuals to make decisions shaping people's lives and fortunes is one of the oldest and most fundamental goals in the liberal ideology, which in turn was the guiding spirit underlying the design of the American governmental system.

Competitive market processes resolve economic problems impersonally rather than through the control of individuals (including companies) or government officials. Control by an individual company or government agency often provides a lightning rod for frustration over economic changes, but less so when the economic impact results from the impersonal competitive market.

Another fundamental political argument for a competitive market is freedom of choice -- the right to choose from whom you will purchase a product or service. This argument is frequently heard with respect to the purchase of electricity. While few, if any, products or services are subject to perfect competition in the American economy, a wide range of choice exists for most products and services, including those which are considered to be essential. The right to exercise economic choice in personal and business affairs is important to many individuals and corporations alike. Similarly, the right to enter into a business is an important freedom.

The concept of customer choice has been emphasized in the current debate over restructuring of the electric utility industry. The Electricity Consumers Resource Council, a national organization of large industrial companies, labeled its plan for deregulation a "Blueprint for Customer Choice," citing customer choice as a "*powerful weapon against the abuse of market power*." The Virginia Committee for Fair Utility Rates, a group of industrial companies, entitles its initial position paper on restructuring as "Position on Greater Customer Choice and Competition in the Electricity Market." Clearly, the right to select a supplier and to negotiate the terms and conditions of service is important to many consumers.

Many customers -- especially municipals at the wholesale level and industrials at the retail level -- have been clamoring for the right to choose electric suppliers. Significant change is occurring at the wholesale level through the movement toward open access transmission. At the retail level, utilities have felt increasing pressure from large customers for lower rates and/or greater access to alternate supplies. In some states, utilities have discounted rates directly and implemented cogeneration-deferral rates, real-time pricing rates, interruptible rates, and other options which provide customers with lower prices and greater flexibility. These measures are motivated by the perceived need of utilities to respond to demands for choice and for lower rates by those customers who represent significant load and are in the best position to gain and exercise the right to shop for electricity. The right to choose suppliers (i.e., retail wheeling) is the ultimate negotiating tool sought by such customers.

Economic

From a societal perspective, a compelling argument for competitive markets is economic efficiency. Competition, in contrast to pervasive regulation, creates the incentives to attain an efficient allocation of resources and to maximize the overall welfare of consumers and producers. In a competitive market, prices reflect the cost to society of producing a good. Profits will not rise above the level of the opportunity cost of capital, as in the case of monopoly profits. If profits are higher than opportunity costs, new entrants will come into the market. New entrants expand industry output and drive prices down, until prices again reflect the cost of the good to society. This competition helps to supply the quantity demanded by customers at prices which reflect the value of the goods to society at large.

Three characteristics of competitive markets have important implications for society and for consumers. First, efficiency of resource allocation is maximized because under competition there is an economic incentive for firms to continue producing up to (and only to) the point where the revenue received from the sale of the last unit produced equals its cost of production, and customers will pay no more than that cost. No additional resources will be committed to produce goods for which the cost exceeds the price consumers are willing to pay, nor will resources be withheld from the production of goods whose price exceeds their cost of production. Second, perfectly competitive markets possess a property that is generally considered desirable in terms of equity of income distribution because extraordinary profits are absent. Market action will prevent a seller from collecting more than the competitive price from buyers. Third, under competition resources are used in a manner which promotes maximum production efficiency, because firms that fail to operate at the lowest unit cost will be driven from the industry.

With the prospect of competition now looming for existing electric companies, dramatic cost cutting is taking place, providing evidence that excessive costs have existed under the traditional regulatory system and that the threat of competition is a highly effective means of controlling costs and promoting maximum efficiency. The downward pressure on costs and the incentive for reliable performance should be consistent where firms are competing, and the potential magnitude of savings to consumers may be significant.

Another benefit associated with competition is the strong incentive for technological innovation -- offering cost-saving changes and product diversity. The prospect of deregulation and introduction of competition may spur entrepreneurial interest in new products and services designed to meet competitive pressures and reap the rewards associated with successful product development. In the telephone industry, the movement toward deregulation seems to be providing a strong incentive to offer new, innovative services. The increased offering of new services and innovations in the electric industry are difficult to project, but unconstrained markets encourage such offerings.

A perfectly competitive electric market will not be attained, but given the benefits associated with competition, it is the standard against which actual markets are measured. Even though economists debate the validity of the assumptions of the competitive model, experience has proved that workable competition offers significant benefits over alternate economic systems.

The principal caveat is that workable competition must develop in order to obtain the benefits discussed in theory. For competition in the electric industry, it is necessary that the number of firms engaged in the competitive segments of the industry should be as large as scale economies permit. Most importantly, there should be no barriers to mobility and entry. Given the current structure of the electric industry, it may be difficult to eliminate these constraints. Utilities are vertically integrated and control what will likely remain the monopoly functions of transmission and distribution in addition to their generation facilities. As in other public utility businesses subject to varying degrees of competition, control of monopoly elements can produce bottlenecks (i.e., barriers to entry), thus the elimination of monopoly control becomes a principal focus of legislators and regulators. This issue may be problematic in the electric industry. Even if transmission, distribution, and generation are structurally separated, concentrations of generation assets in the hands of a few firms which are geographically isolated from potential competitors may produce market power in generation. Mergers of utilities and buy-outs of non-utility generators by utility companies may exacerbate the problem if left unchecked.

Other steps may also be important in establishing effective competition. Oligopolistic pricing does not protect the public interest, so the market should be structured in such a way that prevents price leadership among rival firms. Antitrust law will have an important role, because firms must achieve their goals independently, without collusion. Under a new market structure, inefficient suppliers and most customers should not be shielded from the effects of competition permanently, though some protection may be required during a transition phase.

In sum, the competitive model, at least in theory, offers a good approach for the public to attain efficiency, optimal price, and customer choice over the long run. It is important to bear in mind, however, that the theoretical benefits may have to be tempered and qualified and, most importantly, development of the appropriate market structure must be carefully considered and encouraged in order to foster competition. The presence of market power will be a major consideration in any fundamental restructuring of the electric industry. The need to protect customers and utilities during a transition phase will present a formidable regulatory and legislative challenge.

The overall benefits of competition must also be evaluated against present rates and services in Virginia. Under deregulation, could Virginians be injured as higher cost regions obtain access to lower cost supplies? Considering the low-cost depreciated plant of some utility operations in Virginia, a market clearing price for electricity today for all consumers may not be below or even equal to prices under current regulation, though some consumers could benefit from the current suboptimal capacity mix. Under deregulation, a danger for at least some Virginians is that, without appropriate safeguards, consumers could lose some of the benefits of low-cost utility plant investments which they have supported through rates historically. Finally, it must be recognized that market forces can be brutal, and claims that every customer will benefit from a move to a more competitive structure are highly suspect and likely misleading. As in other free markets, buyers and sellers will be accountable for their own decisions, and those with superior skills, information, and resource endowments will have the greatest opportunity to succeed.

B. Review of Deregulated Foreign Electric Markets

Proponents of electric utility deregulation have identified a number of potential benefits from deregulation, including price reductions and improved service. Some advocates of deregulation argue that it would create a much more competitive utility industry and would enhance the global competitiveness of the United States by lowering prices.

In order to test the validity of such claims, we analyzed price and reliability trends for selected deregulated foreign markets. The reference material reviewed cited general examples of lower prices and improved productivity without providing any detailed support or analysis.

Price comparisons have inherent limitations and may not fully communicate real price differences within a country or region. Price differences are not necessarily indicative of efficiency and may be attributable to numerous factors including fuel mix, proximity to fuel supplies, social policies, technology, and unit vintages. Price comparisons with other countries are also subject to distortions caused by currency exchanges, differing rates of inflation, and other factors.

U.S. Energy Prices and Trends

Based on information reported by the International Energy Agency, average U.S. electricity prices appear to be very competitive with those of other countries. The data indicate that average U.S. industrial prices at 4.7¢ per kilowatt hour ("kWh") were the fourth lowest of 20 industrialized countries in 1994 despite having the second highest ratio of industrial rates to residential rates. The average industrial price of electricity for Canada, Finland, France, Germany, Italy, Japan, Mexico, Norway, the United Kingdom and the United States for 1982-1994 are summarized on Graph III-B1. Compared to other countries on the graph, average U.S. industrial prices have been relatively stable since 1982.

Average U.S. electricity prices for households are also fairly comparable to those of other countries. The 1994 average U.S. household price of 8.4¢ per kWh was the sixth lowest price of 22 industrialized countries. The average household cost of electricity for Canada, Finland, France, Germany, Italy, Japan, Mexico, Norway, the United Kingdom and the United States for 1982-1994 are summarized on Graph III-B2. Unlike industrial electric prices, U.S. electric prices for households have risen since 1982. U.S. prices, however, increased by only 21.7 percent for the period 1982-1994, while increases for other countries were greater (29.4 percent to 111.0 percent).

As noted earlier, the International Energy Agency did not report electric costs for Chile or Argentina. Although a separate report issued by the World Bank includes information on energy prices in Chile and Argentina, this information was not included in the above analysis due to differences associated with converting foreign prices to U.S. dollar equivalents. Based on the World Bank report, U.S. electrical prices also compare favorably to those of Chile and Argentina.

The fact that U.S. electric prices are competitive and stable does not necessarily mean that our electric industry model is superior to other models. It simply indicates that our existing system has not produced high prices relative to other industrialized nations and that benefits associated with competition-related efficiency gains may be overstated. In fact, estimates of efficiency losses suggest that while monopoly-related losses do occur, these losses are not very significant. There are, of course, areas in the U.S. where electric rates are unacceptably high. These high rates may be due in part to regulatory policies and requirements. There is a greater probability that competition will produce positive results in such regions.

The British Experience

The British Electricity Act of 1989 privatized the bulk of the British electricity supply sector and established an unregulated power pool. The changes established under this act became effective on March 31, 1990. Changes included privatization and the transfer of certain activities performed by the government owned utility, the Central Electricity Generating Board ("CEGB"), to four successor companies. Three of these successor companies are engaged predominantly in generation. The high voltage transmission system, also formerly owned and operated by the CEGB, was transferred to a fourth company owned by a holding company, which is owned by twelve regional distribution companies. Transmission and distribution activities continue to be regulated while generation is deregulated.

Generation prices are established through bilateral contracts and by a power pool where generators submit bids to supply power to the pool. Power pool payments to winning bidders reflect two components, a spot energy price and a capacity component. The spot price is the price of the highest bid accepted in each half hour. The capacity component compensates generators for making units available even if those units do not run. The rationale for the capacity payment is that it provides generators with an incentive to make generation available and investors with an incentive to add additional capacity. Retail customers with maximum demands of 100 kilowatt ("kW") or more have direct access to suppliers. while smaller customers will have direct access in 1998. Customers with maximum demands between 100 kW and 1 MW were given access in 1994.

We analyzed average electricity prices published by the International Energy Agency in an attempt to gauge the impact of British electric utility reforms. Based on price trends between 1991 and 1994, it appears that electric utility reforms may have contributed to lower costs in Britain. However, the electricity price trends in Britain are only slightly better than those in the U.S., where prices are still much lower. Some critics of the British model claim that prices would have been even lower for customers in Britain under continued regulation. For example, Tim Woolf of the Tellus Institute reports that a study by the Regulatory Policy Institute found that, on average, residential consumers paid electric prices that were 25 percent higher than what would have been expected based on pre-privatization trends, while industrial customers paid prices 19 percent higher.

One potential benefit of electric supply deregulation is that utilities may have a greater incentive to aggressively bargain for fuel supplies. To test this hypothesis, we analyzed trends associated with U.S. and British fuel prices for generation. Coal prices for the years 1982-1994 for electric generation in Britain and the United States and seven other countries are summarized on Graph III-B3. The graph shows that coal costs for electric generation have declined in both the United States and the United Kingdom since 1982. Natural gas costs for utilities also fell in both the U.S. and the U.K. during the period 1982 through 1994. The cost of natural gas for electrical generation for various countries is presented on Graph III-B4.

The decline in fuel prices for utilities in Britain seems to imply that the British electric utility reforms have encouraged more efficient fuel procurement for electric generation. However, other factors may also impact fuel costs and the decline in coal prices for electricity may be attributable to other factors. For example, deregulation of natural gas production and other gas related regulatory reforms in the U.S. may have helped to lower natural gas costs. Therefore, we also analyzed fuel costs for other market segments to see whether fuel price trends for electric generation were different from those for other market segments.

Between 1991 and 1993, coal prices in the United Kingdom declined significantly more for non-utility industries than for British power suppliers. Conversely, declines in U.S. coal costs for electric generation were greater than declines for non-utility industries during the same period. This implies that factors unrelated to utility reforms may have contributed to the lower coal prices for generation in Britain. However, non-utility industrials in Britain may have had a greater ability to obtain lower cost coal supplies since generators were required to obtain almost all of their coal supplies under take-or-pay contracts from British coal companies during 1990-1993. This requirement was included as one of the transition mechanisms to a more competitive market. The average prices paid under these contracts were significantly above the price of imported coal.

Non-utility industries in Britain also experienced greater percentage price reductions than utilities for natural gas. Industrial gas prices are presented on Graph III-B 5. Gas prices for electric generation fell only slightly faster than that for households in Britain. U.S. gas prices for electric generation decreased during this period, while gas prices for U.S. households and industries increased by 17 percent and 2 percent, respectively.

The above comparisons provide little support for duplicating the British electric industry model in the U.S.. While our study of electric rates indicates that British electric prices have fallen at a slightly faster rate than U.S. prices in recent years, it is unclear whether this decline is attributable solely to electric utility reform. The decline in British electric costs is partially attributable to reduced fuel costs that may be associated with factors other than increased competition.

Our conclusions regarding the customer impact of the British reforms are similar to conclusions reached by Gordon MacKerron of the University of Sussex, who indicates that shareholders have been the main beneficiaries of the British utility reforms and that stable electricity prices accompanied by increased profitability did not increase efficiency. He indicates that stable prices were a result not of reform but of sharp decreases in the prices paid for coal and gas. MacKerron also states:

...A major part of the difficulties we have experienced in England and Wales derives from a rushed and poorly managed initial structure and portfolio of contracts, and much of the regulatory task has been to clear up the mess left by this initial settlement. Taking time and getting a fair balance between the various parties seems essential to subsequent success in a competitive experiment.

The final lessons concern the regulatory approach. We are now dominated, in British regulation, by the notion that regulation is all about economic efficiency and that this in turn is axiomatically best promoted by more competition. There are dangers here. One is that it is too readily assumed that there are no significant efficiency benefits to be won from co-ordination or integration to set against competitive benefits, and second there is an undue concentration on economic efficiency at the expense of equity and social consensus. However large the benefits of improved efficiency may be, they cannot forever remain paramount in the political process if the equity consequences are persistently adverse....

There is, however, some indication that the British reforms have increased productivity. For example, in 1992 National Power plc, the largest generator in the United Kingdom, announced layoffs totaling 8,000 (47 percent of total number of employees) since privatization. These cuts occurred during a period when National Power's market share was decreasing, the total reserve margin of British utilities was 26.8 percent, and reserves were expected to grow to 57 percent by 1997. Based on National Power's declining market share and the prospect of further declines, it is reasonable to assume that the staff reductions were at least partially a result of excess capacity, which reduces the need to maintain a higher level of generating unit availability. Higher reserve levels reduce the need for shorter maintenance outages and allow utilities to perform repairs without the need for excess labor costs.

MacKerron and others have criticized the British model because it initially established only two private sector generators and did not allow significant competition in the power supply market. Derek W. Bunn of the London Business School states:

An evident requirement of efficient marginal cost pricing in a competitive market is sufficient competition at the margin. In the UK, that has not been the case, with PowerGen and National Power effectively controlling the marginal plant and thereby setting SMP [system marginal price of the pool].

There also appear to be a number of technical problems with the operation of the British pool and the development of rates for transmission and distribution services. These problems, combined with the lack of true competition in the generation market, have apparently allowed utilities in Britain to improve earnings while electric customers have, on average, seen little if any benefit. In fact, certain customers may have actually experienced significant rate increases.

Further evolution of the British system and the development of additional generators may reduce the market share of the two original private generating companies and cause greater competitive pressures. However, the British government lifted restrictions regarding the acquisition of regional electric distribution companies in 1995 and the majority of the distribution companies have been subject to mergers or takeover bids. These activities increase the vertical integration of the British electricity market and could decrease competitive forces since generating companies have been allowed to acquire regional distribution companies which share ownership of the transmission system. Such integration could potentially allow generators to exercise control over the distribution companies and thereby hinder competition.

The British model involved movement from a government-owned system to privatization, while utilities in the U.S. are mostly privately owned. Consequently, utility reform in Britain may offer certain benefits that are not available in the U.S. Government-owned enterprises are thought to be less efficient than privately owned interests because the owners and managers of privately owned ventures have a profit motive. For example, it has been estimated that a 2,000 MW coal plant was manned by 844 people in Britain and that a comparable plant would be manned by 500 people in the United States. Therefore, U.S. utility reforms may stimulate utility efficiencies to a lesser degree than can be achieved in other systems that are or were predominantly publicly owned.

Stranded cost implications may be different in Britain than in the U.S. because in Britain such costs were absorbed by a governmental body rather than a single business entity or narrow groups of utility ratepayers. One implication is that stranded costs are easier to recover in Britain because they are spread across a larger base (taxpayers) and may, consequently, be given less attention. A second implication is that there may be less incentive for minimization of stranded costs in Britain. For example, Electric Utility Week reported that an investigation by the U.K. National Audit Office concluded that the British government sold the regional electric companies at too low a price in its rush to complete privatization. This implies that although utility consumers in Britain may benefit from lower utility rates, they may be subject to a higher tax burden.

In summary, we believe that the British model provides limited support for electric utility reform in the U.S. The British experience highlights the negative implications of market dominance by too few competitors and hasty industry restructuring. It appears that the benefits of lower utility costs may not be shared with consumers if utilities are allowed to control the market through concentration in the ownership of generating facilities and vertical integration. Perhaps the most pertinent lesson from the British experience is that rushed or poorly managed attempts to restructure the electric utility industry may have adverse consequences for consumers.

The Norwegian Experience

The Norwegian Energy Act, which became effective in 1991, introduced third party access to the retail market and competition in electricity production. This act created competition for the sale and purchase of electricity and allowed customers to buy from any generator, trader or the electricity pool. Hourly metering is mandatory for larger customers while transactions for smaller users are estimated based on the system load profile of their respective network. Transmission and distribution services continue to be monopoly services with network owners providing wheeling service to connected customers. Surveys conducted in 1993 and 1994 by the Norwegian Water Resources and Energy Administration indicate that most prices for residential customers had fallen as a result of competition. However, a 1995 survey indicated that prices had increased since the earlier surveys.

Based on the electricity prices reported by the International Energy Agency, it appears that the Norwegian electric utility reforms may have contributed to lower rates. However, Norway's generation is 99 percent hydroelectric and the major heating source is electricity. Consequently, electricity supply and demand in Norway varies with water inflow and temperature and electrical price variances may be associated with factors other than industry reform. It is also important to recognize that Norway's hydroelectric based system offers certain advantages over thermal based electrical systems. Frequency control and operational planning are made easier by the fast response characteristics of hydroelectric units. Hydroelectric facilities may also act as storage devices and help dampen the impact of peak loads.

The Norwegian experiences provide support for U.S. electric utility restructuring because Norway's electric prices have declined as a result of competitive pressures despite the fact that Norway's electric rates had been competitive and stable. However, the Norwegian utility reforms have only been in effect for a short time and the long term impact of these reforms is not known. In fact, some producers have complained that price pressures are threatening their viability. Producers and vertically-integrated utilities are still financially sound due, in part, to cross-subsidization from the wires businesses with profits decreasing by 31.8 percent, on average, for 12 large production-only utilities representing half of the Norwegian production capability. Generating companies could experience problems without this subsidization. In addition, with Norway's generation being 99% hydroelectric, its system's characteristics are so different from the U.S. electric system that results from similar experiments may not be parallel.

The Chilean and Argentinean Experiences

Chile pioneered electric utility privatization and deregulation by beginning the deregulation process in 1978 and by promulgating a new electricity law in 1982. Argentina followed with a more aggressive process initiated in 1991. Stranded assets were not directly recovered in either of these restructuring initiatives. Argentina has two interconnected systems with a present installed capacity of approximately 18,000 MW. Chile also has two interconnected systems with the main system having an installed capacity of about 4,000 MW. The two industry models are very similar and involve corporate separation of the generation, transmission and distribution functions. The Chilean model does not impose restrictions on vertical integration while the Argentinean model restricts the controlling owners of generation and distribution companies from owning a controlling interest in a transmission company. These structural characteristics are considered important in developing an effective competitive industry. Generation companies in Argentina cannot have a market share greater than 10 percent. The two models provide for the unbundling of transmission services and the provision of open access transmission. Transmission and distribution companies are assumed to be natural monopolies and are subject to cost-of-service regulation.

The industry reforms also included the establishment of unregulated-centrally-dispatched-commodity markets (power pools) and parallel-bilateral markets (in which a producer and user can sign a power contract for any length of time). Generators receive two types of payments from the power pools: a payment for energy dispatched by the pool and a capacity payment for capacity offered to the grid. The energy price is based on the cost of the most expensive energy dispatched by the pool, while the capacity payment is based on the value of marginal capacity (the cost of a peaking unit). Both models include retail wheeling for certain large retail customers.

There is some concern that the initial lack of restrictions on cross-ownership and shares of generating markets has allowed market dominance in one of the Chilean systems. The northern system, dominated by a number of large sophisticated users, has developed fierce competition while the second system is dominated by one private generating company. One investment group controls the majority of the generating capacity, the largest distribution company and the transmission system in the second interconnected system. It is not clear to what extent that this market dominance has increased costs to retail customers.

As noted earlier, residential prices rose in Chile by approximately 10 percent while U.S. residential prices declined by approximately 7 percent (based on 1992 U.S. $ equivalents) between 1978 and 1991. Chilean and U.S. industrial prices declined by approximately 8 percent and 17 percent respectively during this same period.

The industry reforms in Argentina appear to be very successful. In Argentina monthly average wholesale prices have declined from $50-60 per megawatt hour ("MWh") to $30 per MWh during the period June 1992-September 1994. Availability of generating units in Argentina has increased from a historic low of 47 percent in 1992 to 70 percent in 1994. Unit availability is expected to increase to 80 percent in 1996. Productivity has improved from 0.91 worker/MW to 0.57 in the generation business and from 0.86 worker/MW to 0.56 in the distribution business.

The Chilean and Argentinean experiences seem to indicate that competitive forces will produce a number of significant benefits particularly in areas where utility efficiencies are low. These experiences also provide useful insights into the proper structure of power pools. While we believe that the industry reforms in Chile and Argentina have generally produced positive results, this belief is based on limited information and a limited history. Electricity costs in these South American countries seem to be higher than U.S. costs despite abundant hydroelectric resources and lower natural gas costs. The Argentinean unit availabilities, while improved significantly, are still below U.S. averages. The lower U.S. electrical rates and higher unit availabilities may show that there is less to be gained through a massive restructuring of the U.S. electric utility industry. It also may be more difficult to deal with stranded cost problems in the U.S. because most U.S. utilities are privately owned.

C. Advances in Technology

Throughout modern history technology has often been the precipitator of industrial change. Technological innovations were the primary cause of transformation of the telecommunications industry from the once staid monopoly utility to the dynamic business it is today. Although the electric industry has not duplicated the technological advances seen in telecommunications, improvements in electric equipment have enhanced the opportunity for competition to develop in the electricity market. Small, efficient units with low average installed costs have reduced the capital requirements for constructing new generation and as a result have reduced the barriers to entry in the generation market.

<u>Natural Gas Fueled Generation Technologies</u>

Two technologies have been used in gas-fired electric generators. The majority of existing gas-fired capacity consists of boilers that produce steam to drive generators. The alternative technology is a combustion turbine. Historically, turbines have been used in simple cycle systems as peaking units or in combined-cycle systems with steam turbines as intermediate load plants. While simple cycle combustion turbines systems continue to be used for peaking capacity, both utilities and NUGs appear to be increasingly using combined-cycle power plants for new intermediate load capacity. In some cases, combined-cycle power plants are being used even for base-load capacity.

Where gas or oil is available as a fuel, combined-cycle combinations of gas turbines, exhaust heat boilers and steam turbines are well established as a relatively simple and efficient means of generating electricity. The term "combined cycle" is applied to a plant possessing a mix of both gas and steam turbines. The idea is not new, and early applications of the principle took place shortly after the gas turbine first became a practical means for generating electric power.

The combined cycle is a particular application of the general principle of using gas turbine exhaust heat to generate steam, which is then usable in a variety of ways. Early applications ducted the exhaust gases into conventional boiler furnaces instead of the normal air supply. It was soon realized that the same result could be obtained by using a simple unfired exhaust boiler that generates steam to drive a steam turbine.

Worldwide demand for combined-cycle power plants grew exponentially during the 1980s, and most forecasts call for the boom to continue. The reasons are clear: the combined-cycle power plant is the most efficient electric generating system commercially available today. It also has capital costs significantly lower than competing nuclear, fossil-fired steam, and renewable-energy stations. In addition, its low air emissions, water consumption, space requirements, and physical profile are significant advantages in an era marked by tough permitting and siting processes. A recent advance that may further cement the combined-cycle's front-running position is combining the gas turbine, steam turbine, and electric generator on a single shaft. Locking together the turbines and generator to form one single-train operating system promises to simplify plant design and operation, and may lower capital costs.

There are several advantages to the combined-cycle plant compared with conventional reheat-steam plants of a similar rating. Full combined-cycle generation can usually proceed in less than twelve months after operation of the first gas turbine. The short delivery time for gas turbines means that the decision to proceed with a combined-cycle development can be delayed beyond that for a thermal station, thus giving more flexibility to the system planner when viewing load projection forecasts. Also, the return on capital is quicker, arising from early operation of the gas turbine plant, albeit with some cost penalty compared with the ultimate development due to the lower thermal efficiency of open cycle generation.

While steam cycle technology is mature and relatively few innovations have occurred to improve its efficiency, the improvements in gas-turbine technology have boosted both simple cycle and gas combined-cycle efficiencies and further significant improvements are expected. Net thermal efficiencies for natural gas fired combined cycles are being demonstrated in the 54-55 percent range. Combustion turbines have been introduced that are expected to operate with simple cycle efficiencies of 38.5 percent and to have efficiencies of 58 percent in combined-cycle applications.

In addition, the unit capital costs of conventional combustion turbines have decreased significantly in this decade which will decrease the cost of both simple cycle and combined cycle applications. For example, while Virginia Power's Darbytown combustion turbines were completed in 1990 at a cost of $289 per kilowatt, the company is now projecting the unit capital cost of conventional combustion turbines to be $211 per kilowatt. The reasons for past and projected decreases in the capital costs of combustion turbines include increased competition and levels of production, economies of scale from larger units, increased unit thermal efficiencies, and the elimination of the need for expensive post-combustion nitrogen oxide ("NOx") emission controls as a result of the development of dry low-NOx combustors.

A comparison of selected indices for combined-cycle plants, combustion turbines and conventional coal plants recently installed in Virginia is provided in Table III-C1. The latest assumptions by Virginia Power about the performance characteristics of potential new generating units are presented in Table III-C2.

Natural gas consumption is expected to continue to grow well into the 21st century. Much of this growth will be driven by environmental considerations as well as by the increased competitiveness within the natural gas market. Future growth will continue to be concentrated in electricity generation, including electric utilities and NUGs. At the end of 1994, U.S. utilities planned to build 28 new gas steam units and 250 gas-fired combustion turbines through 2004. The trend of increased use of gas-fired generation is expected to continue through 2015.

Fossil fuels which accounted for 70 percent of electricity generation in 1994, are projected to account for 79 percent in 2015. Much of this increase is in the use of natural gas, which currently fuels 14 percent of total generation but is expected to grow to 27 percent by 2015, supplanting nuclear energy as the nation's second largest energy source (after coal). Three factors explain this trend. First, although the utilization of existing nuclear power plants is increasing, 37 gigawatts of nuclear capacity are assumed to be retired by 2015, with no new nuclear orders on the horizon. Second, as discussed above, combined-cycle technologies are demonstrating efficiencies up to 60 percent, compared with 35 percent for coal-steam technologies. Third, between 1994 and 2015, gas prices to utilities are projected to increase by only 1.4 percent annually.

There are several programs under way to advance combustion turbine technology. The U.S. Department of Energy ("DOE") is especially active in sponsoring research. In 1993, it began an ambitious 8-year program known as the Advanced Turbine System program. The main objectives of the program include combined-cycle efficiency of 60 percent and simple cycle efficiency of 40 percent, environmental superiority over existing technology and capability to be fueled by coal or biomass.

Of particular promise in the future is the integration of pressurized solid oxide fuel cells into combustion turbine cycles. By integrating the fuel cells as a pre-gas-turbine-inlet topping cycle, efficiencies in excess of 65 percent can be attained, even in smaller (1-20 MW size) power plants. Fuel-flexible and highly efficient, fuel cells directly convert the chemical energy of natural gas, coal, biomass-derived fuel gas, or a distillate fuel gas to electricity. With no combustion, no noise, and simple cycle efficiencies approaching 50 percent, fuel cells are one of the advanced technologies being developed that can have a major impact in the quest for long-term, worldwide energy solutions.

Although the advancements in gas technologies and increased use of gas have many potential benefits, careful planning may be needed to ensure an adequate supply can be delivered. With the increasing use of natural gas for electricity production, there is concern about gas delivery reliability problems that can occur, particularly during periods of extreme cold weather. In particular, interruptible gas sales can be shut off to utilities and non-utilities during cold weather to allow supply to population centers for heating homes and businesses. The interruption of natural gas to utilities and non-utilities could have an adverse effect on generation.

D. Excess Capacity Situation

Proponents of electric utility restructuring often cite the current low cost transactions in the spot and wholesale electric power markets as examples of the potential benefits of a competitive market. It is generally accepted that lower prices have been driven by an excess supply of generating capacity.

We reviewed capacity reserves for the reliability councils serving Virginia and nearby regions in an attempt to determine whether there is an excess of capacity within our region and to gauge whether the lower cost of off-system transactions can be attributed to excess capacity. Reserve margins, which have traditionally been used to gauge the reliability of an electric system, can also be used to examine the potential for higher or lower electric prices. Based on data compiled by the North American Reliability Council ("NERC"), actual summer reserve margins were calculated by Staff for the East Central Area Reliability Coordination Agreement ("ECAR"), the Mid-Atlantic Area Council ("MAAC"), the Mid-America Interconnected Network ("MAIN"), and the Southeastern Electric Reliability Council ("SERC").

The results of these reserve margin calculations are presented on Graph III-D1. As can be seen from this graph, reserve margins for the four reliability councils have declined since 1984. Reserves were quite high in the early to mid-1980s, with margins of 30-40 percent. However, reserve margins dropped to 16.8, 17.1, 18.6 and 20.2 percent in 1994 for SERC, ECAR, MAIN and MAAC respectively.

Although reserve margins have declined to historically low levels, they are consistent with current utility forecasts of minimally acceptable reliability levels. Some may argue that these reserve levels are excessive in light of competitive pressures, the potential for stranded costs, and increased transmission access at the wholesale level. The support for low reserve margins comes during what may be a transition to a competitive market where producers will receive greater rewards if power supplies are constrained. It also is indicative of risk aversion on the part of electric utilities that do not want to be saddled with costly capacity as competition appears to be increasing.

Even with high historic reserve margins, power supplies have been occasionally limited as a result of forced generating unit outages, scheduled maintenance or extreme weather. In fact, Virginia Power and the PJM (Pennsylvania-Jersey-Maryland power pool) systems were subjected to rolling blackouts in January, 1994 due to, among other things, abnormally low temperatures. Also, the PJM system instituted voltage reductions and curtailed service to interruptible customers on May 20 and 21, 1996, as a result of unseasonably warm temperatures.

While prices for spot- and limited-term power sales have generally been lower than the embedded cost of utility supplies, prices can increase dramatically during periods of limited supply. Consequently, the frequency and duration of supply limitations will influence whether overall electric prices are higher or lower. Although periods of surplus capacity likely will occur due to the extreme variability of seasonal electrical loads, lower reserve margins will increase the frequency and duration of supply shortages and increase the likelihood that prices will be volatile in a competitive environment. Assuming a competitive environment, higher reserves will actually increase the probability of lower cost because of the law of supply and demand.

Certain customers may be adversely affected by power supply deregulation if their electrical requirements correspond to periods of undersupply even if overall prices are lower. For example, customers who use electricity primarily for space conditioning (heating and cooling) are less likely to experience lower overall electric prices and are more likely to experience higher prices as a result of their needs coinciding with supply constraints during periods of extreme weather. Customers who use electricity for process or production needs may not be impacted as greatly by weather related supply constraints.

Capacity Mix

Another reason current spot and wholesale transactions may be priced at lower levels is the sub-optimal mix of generating capacity within our region. An efficient capacity mix is expected to include a mixture of base-load units, intermediate units and peaking units since electrical loads vary over time with intermittent periods of peak demands. Base-load units are typically nuclear or coal-fired with high-fixed costs and low-operating costs. Peaking units, which are typically oil- or gas-fired combustion turbines, have low-fixed costs and high-operating costs. Intermediate units are typically older coal units, oil units, or natural-gas-fired combined-cycle units. A capacity mix may be sub-optimal if there is too much or too little of one type of capacity. For example, it would be uneconomic to construct a coal unit to serve peak loads of limited duration since the unit would be operated over a limited number of hours and there would not be sufficient variable cost savings to offset the higher fixed costs of the coal unit.

It appears that in the regions surrounding Virginia there is an excess of base load capacity. The average capacity factors of coal units in the ECAR, MAAC, MAIN and SERC reliability regions ranged from 47.1 percent to 62 percent in 1994. This indicates that existing base-load units are being under-utilized because coal units can be operated reliably at capacity factors of 80-90 percent. This excess of coal-fired capacity depresses the cost of spot- and limited-term transactions because the fixed costs of such units are being recovered from captive customers and off-system transactions need not reflect the overall cost of base-load units. Utilities can also use the energy from excess base-load capacity to support lower-cost, longer-term off-system transactions, even if such transactions require the acquisition of additional capacity. Lower-cost peaking capacity can be blended with excess coal-based production capabilities at a lower overall cost than can be provided by either type of capacity individually on a marginal cost basis.

It could be argued that the excess of coal-fired capacity may reduce overall electric prices if utilities are forced to compete in a deregulated market because utilities would aggressively market their low cost supplies. However, these excess base-load capacities are typically included in rate bases that have been approved by regulatory commissions and as such are likely to be deemed prudent in determining stranded costs. If utilities are allowed recovery of stranded costs in exchange for being forced to compete, stranded costs may effectively offset a large portion of the benefits of lower power costs that may be stimulated by the excess of base load capacity.

Effect Upon Prices

An examination of regional reserve margin trends and forecasted reserves does not indicate an excessive amount of supply from a historic perspective. It does appear, however, that there is an excessive supply of base-load coal capacity. This supply of capacity is owned by electric utilities and included in their rate bases. This fact may result in artificially lower transaction prices on the spot and wholesale markets that do not fully reflect the total average costs of generation.

Cited examples of lower-cost, spot- and limited-term wholesale transactions can be misleading because such transactions typically reflect only a portion of the overall costs of generating electricity. Production costs have two primary components: fixed, or capacity, costs which include costs that do not change with energy production, and variable costs that vary in direct proportion to electrical output. Examples of fixed costs include return on investment, depreciation, property taxes, and administrative costs. Variable costs include fuel costs, emission costs (SO_2 allowances), and operating and maintenance costs that are impacted by actual unit operation. Fixed costs are reflected in the development of retail rates and long term supply contracts. Consequently, utilities are assured almost complete recovery of the fixed production costs of a unit that was prudently built and operated regardless of how much that unit is actually used.

Utilities are currently able to engage in off-system transactions (spot- or limited-term wholesale activities) with little need to recover fixed costs. Utilities view short-term transactions that recover any margin in excess of short-term variable costs as economically desirable. Such a system might not be sustainable if power supplies are deregulated because certain customers and customer groups who have limited access to competitive supplies of power would be unwilling to continue funding fixed generating costs while other customers with greater access could purchase supplies at a fraction of their overall cost. Therefore, market prices, especially over the long term, should reflect both fixed and variable production costs if electric supplies were are deregulated. Over the short term it is unrealistic to expect that fixed costs will be stranded and totally borne by utilities' shareholders. Therefore, today's low-wholesale-market prices may not be representative of the cost of electricity in a deregulated environment.

E. Variations in Regional Electric Rates

Electric bills for industrial, commercial and residential customers comprise significant budgetary expenses with enormous economic and social implications. Depending on location, the variances in electric bills among utilities can amount to hundreds of dollars per household, thousands of dollars for small businesses and millions of dollars for industrials on an annual basis, with major impacts on the cost of living and the cost of doing business.

While U.S. prices on average compare favorably with those of other industrialized nations, there are wide differences within the U.S. which explain much of the interest in restructuring. California, which has been the early leader among states in planning a major restructuring of its electric system, has among the highest rates in the United States. Edison International (formerly SCEcorp), for example, has average industrial rates of 7.09 cents per kWh, while AEP's comparable rates in Virginia/West Virginia are 3.68 cents, or roughly half that of the California utility. Similar comparisons can be found among commercial and residential rates.

Sharp differences can also be found within regions of the country, giving at least the perception in higher cost areas that cheaper sources of power are nearby and available. Again using California as an example, its average industrial rate for one utility is 7.50¢ per kWh, while the highest comparable rate is 3.80¢ in Oregon, 4.52¢ in Washington, and 5.96¢ in Nevada. Closer to home, industrial rates for Virginia Power and Appalachian Power average 4.36¢ and 3.68¢, respectively, while Duke Power and Carolina Power and Light in North Carolina average 4.23¢ and 5.12¢, respectively. Comparable costs to the north are higher, with industrial rates in Pennsylvania ranging from 4.54¢to as high as 7.18¢.

Significant differences exist among utilities even within a single jurisdiction. In New York, one utility charges 5.80¢ per kWh on average for industrial customers, far higher than Virginia rates, but much lower than the 12.55¢ and 14.32¢ charged by two other New York utilities. While such differences are not nearly as wide within Virginia, Virginia Power's residential and commercial rates are 48.0 percent and 29.7 percent higher, respectively, than those of Appalachian Power.

In general, the greatest interest and activity regarding restructuring and investigation of competition at the state level has been, not surprisingly, in those jurisdictions with the highest retail rates. Those states where electric bills are highest include California, New York, New Hampshire, and Massachusetts, and these states have been at the forefront of the restructuring debate and the first to set timetables for the introduction of market forces.

F. FERC Order 888 and 889; CRT NOPR

FERC issued a notice of proposed rulemaking ("NOPR") on March 29, 1995, launching an investigation into restructuring the nation's wholesale electric industry. The Commission Staff filed comments in August 1995, as did many other parties, expressing concern with, disagreement on, and requesting clarification of certain issues raised in the NOPR. In our comments we expressed general support of the concept of increased competition in bulk transfers of electricity and improved transmission access, but concluded that the proposed rules violated provisions of the Federal Power Act and did not adequately protect the needs of native load customers and the jurisdictional authority of the states.

On April 24, 1996, FERC issued Order 888, generally adopting the proposals outlined in the NOPR. This rule requires electric utilities to offer third parties comparable wholesale transmission services under open-access tariffs. It also establishes procedures under which utilities may seek recovery of stranded costs resulting from open-access service to wholesale customers. The utility must also provide ancillary services including (1) scheduling, system control and dispatch, (2) reactive supply and voltage control from generation sources, (3) regulation and frequency response, (4) energy imbalance, (5) operating reserve and (6) spinning reserve to customers that do not obtain those services themselves.

FERC also issued Order 889, requiring all transmission providers to establish an Open-Access Same-Time Information System ("OASIS") to share available transmission capacity data and other data. This rule also requires transmission providers to use the OASIS information exclusively in making their own operating decisions. At the same time, FERC also initiated another NOPR to explore the replacement of the pro-forma open-access tariff covering both network and point-to-point transmission services, required in Order 888, with a single capacity reservation tariff ("CRT").

Order 888 requires all jurisdictional utilities which own, operate, or control wholesale transmission facilities to file non-discriminatory, open-access transmission tariffs offering service to third parties that is comparable to the utilities' own use of their transmission facilities for wholesale services. Utilities are compensated for this access through a pro forma tariff describing the minimum terms and conditions of the services provided by the transmitting utilities. Such utilities must also use the same pro forma tariff for their own wholesale energy sales and purchases. Such tariffs were required to be filed by July 9, 1996, and must conform to the FERC's definitional framework. Utilities were permitted to file tariffs determined by alternative means on or after July 10, 1996. Members of power pools and multi-lateral trading agreements must file pool-wide or system-wide pro forma tariffs by December 31, 1996. The rule also requires non-jurisdictional entities seeking service under an open-access tariff to provide reciprocal access to their own facilities. Reciprocity only applies to a transmission provider and not to its corporate affiliates, such as distribution cooperatives served by a generation and transmission cooperative.

FERC will allow utilities offering open access to their transmission facilities the opportunity to recover all legitimate, prudently incurred, and verifiable investment costs stranded by open access. These costs will be assigned directly to customers who leave their traditional utility's system for an alternate supplier. The rule also requires that utilities mitigate stranded costs and establish procedures to inform and enable a customer to intelligently decide whether or not to switch suppliers.

Order 888 discusses state/federal jurisdictional boundaries but refuses to draw a "*bright line*" between state-jurisdictional distribution and FERC-jurisdictional transmission. The Order adopts the seven local distribution indicia described in the NOPR. The seven indicia are: (1) local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems, it rarely flows out; (4) when power enters a local distribution system, it is not reconsigned or transported on to some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographical area; (6) meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and (7) local distribution systems will be reduced voltage.

Some have argued that this seven-factor test is vague and ignores physical realities. For example, a facility "*in close proximity to retail customers*" is not necessarily a low-voltage distribution line. Retail customers may take service at high-voltage from a transmission line. In addition, local distribution facilities need not be radial in character. Distribution circuits may be networked or looped with adjacent distribution circuits. Further, all power is consumed in a restricted geographical area. This fact applies to power entering a transmission system as well as power entering a distribution system. In short, FERC's indicia of local distribution do not provide a reliable test for classifying facilities.

FERC acknowledges that this test does not create a "*bright line*" and that a case-by-case review may be necessary to classify a facility. FERC will give deference to state determinations of which facilities are transmission and which are distribution if states apply the seven-factor test.

Order 888 and the accompanying pro forma tariff may require utilities to construct new facilities to accommodate wheeling transactions. Thus, a state's authorization to approve the construction of new facilities may be required if a utility shows that the new facility is necessary to provide wheeling. Order 888 did not address state siting authority, and apparently the status quo has been preserved. The dual federal and state roles in approving new facilities could lead to delays in constructing new facilities; federal and state agencies must cooperate to avoid a stalemate.

FERC has asserted exclusive jurisdiction over the rates of unbundled retail transmission in interstate commerce. If a utility chooses to provide, or if a state requires, unbundled retail transmission service, that service will be subject to FERC's pro forma tariff. Several state commissions and the National Association of Regulatory Utility Commissioners ("NARUC") have objected to this assertion of jurisdiction. FERC admits that the case law interpreting the division of jurisdiction in the Federal Power Act is ambiguous with regard to unbundled transactions. The FPA's allocation of federal and state jurisdiction was created about 60 years ago, long before unbundling and competition in the electric industry were contemplated. Neither the FPA nor the case law settle the question of jurisdiction over unbundled retail transmission services; no explicit distinctions are made between bundled and unbundled services. Some have argued that all transmission is interstate commerce subject to FERC's jurisdiction, and allowing individual states to assert jurisdiction over interstate retail transmission would lead to economic inefficiency.

While FERC pronounces that state social and environmental programs will not be affected by the Order, such programs may be indirectly harmed. Utilities must cut costs in order to compete in a restructured industry, and it is reasonable to assume that funding social and environmental programs will not receive top priority.

The Order also requires power pools, holding companies, and utilities with bilateral agreements containing discriminatory transmission access and pricing provisions to modify such agreements to comply with the open-access requirements. The FERC will allow utilities to modify existing contracts to provide stranded cost recovery while permitting customers to make modifications to seek alternative supply options. FERC will not set rates for transmission and ancillary services but instead will review utility rate filings.

Order 888 does not require utilities to turn over control of their transmission systems but offers guidelines on creating independent system operators ("ISOs"). Nor does the Order mandate corporate divestiture of utilities' generation and transmission operations. Instead, it requires utilities to functionally unbundle their transmission business from their power marketing business.

FERC recognizes that the magnitude of potential wholesale stranded costs may be small relative to that of retail stranded costs. The Order establishes a role for states in addressing retail stranded costs. FERC asserts that both FERC and state commissions have the legal authority to address stranded costs caused by retail customers who obtain retail wheeling from public utilities to reach a different generation supplier. According to FERC, its authority over retail stranded costs is based on its jurisdiction over the rates, terms, and conditions of unbundled retail transmission. FERC concludes that for policy reasons, it should leave the issue of retail stranded costs to states. However, FERC will not allow states to use the interstate transmission grid to pass through retail stranded costs. FERC will entertain requests to recover stranded costs caused by retail wheeling when a state does not have authority under state law to address these costs. Many have argued that FERC cannot address these costs because a retail wheeling transaction is simply a retail transaction, with no costs over which FERC may assert jurisdiction. Thus, FERC must leave the identification and recovery of retail wheeling stranded costs to the states.

Section 201(a) of the FPA limits FERC's jurisdiction to "*the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce*," and extends "*only to those matters which are not subject to regulation by the States*." Costs a utility incurs to serve its retail customers do not involve the sale of electric energy at wholesale nor interstate transmission, so they are not subject to FERC's jurisdiction. Further, retail wheeling may only happen pursuant to a state law, so the recovery of retail wheeling stranded costs is subject to state regulation.

In addition to asserting jurisdiction over stranded costs caused by retail wheeling, FERC claims it should be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. According to FERC, costs stranded by a customer reaching a new generation supplier through open access are stranded because of a FERC action. Thus, there is a connection between the FERC-jurisdictional open access requirement and the exposure to stranded costs. FERC declines jurisdiction over stranded costs arising from an existing municipal utility annexing territory served by another utility or otherwise expanding its service territory. According to FERC, there is no direct connection between the FERC-jurisdictional open access requirement and the exposure to stranded costs.

FERC's assertion of jurisdiction over retail-turned-wholesale stranded costs has also been criticized. The costs incurred on behalf of retail customers are retail costs, subject to state jurisdiction. Although there is a wholesale transaction between a utility and a retail customer turned wholesale, that transaction does not involve any embedded costs a utility incurred on behalf of its retail customers. Like retail wheeling, municipalization can only happen pursuant to state law. Thus, stranded costs associated with municipalization would be subject to state regulation.

Order 889 sets forth requirements for establishing transmission information networks and standards of conduct. The rule describes the information that must be posted on OASIS, the procedures that utilities must adhere to in response to requests for transmission service, and the standards and protocols for posting information on OASIS. Each transmission provider must operate an OASIS by November 1, 1996, on the Internet, accessible through the World Wide Web.

Additionally, this rule defines strict standards of conduct mandating separation of utilities' wholesale power marketing and transmission operation functions. Utility employees performing merchant functions must obtain transmission information to provide wholesale transactions in the same way as competitors, through OASIS. This prevents transmission providers from giving themselves an undue preference over competitors. However, in emergency situations affecting system reliability, transmission providers may take any necessary steps to preserve the system's integrity and report such events to FERC and OASIS within 24 hours.

The Capacity Reservation Tariff NOPR proposes a single tariff where utilities and all other power market participants would reserve firm rights to transfer power between designated receipt and delivery points. This is based on the point-to-point service in the Order 888 pro forma tariff. A CRT would provide all customers the same degree of flexibility in reserving and using transmission service. All transmission customers would specify the amount of power to be received and delivered at multiple receipt and delivery points and would have substantial flexibility in rearranging these receipt and delivery points. Transmission rights and prices would be based on capacity reservation instead of the prevailing industry practice of load-rates pricing.

According to FERC, this reservation-based service is more compatible with open access because market participants can find out how much transmission capacity is available. FERC also believes that requiring all market participants to reserve transmission capacity will help transmitting utilities plan for system upgrades. Transmission customers would be required to forecast their needs and commit to them in the reservation process. Comments received regarding the NOPR indicated that a single-service, open-access tariff may be more compatible with open access and better accommodate competitive changes occurring in the industry, such as more flexible transmission pricing.

On May 24, 1996, the Commission Staff filed a request for rehearing of Order 888. The Staff believes Order 888 is improper because FERC exceeded the scope of its statutory authority by requiring generic industry-wide unbundling, open access, and comparability, and FERC's finding of industry-wide undue discrimination is not supported by the record. In Staff's view, FERC's assertion of jurisdiction over the rates, terms, and conditions of unbundled retail transmission services, over stranded costs related to retail wheeling, and over stranded costs from retail-turned-wholesale customers, is contrary to law. The reservation and curtailment priorities of the pro forma tariff fail to protect native load customers who have borne a significant portion of the costs of the existing transmission system. Also, FERC improperly interfered with state authority to determine the necessity for upgrades and construction of transmission facilities. Approximately 135 other commenters filed requests for a rehearing of Order 888 and/or Order 889. To date, FERC has not ruled on the requests for rehearing.

G. Federal Legislative Activity

Following on the heels of the Energy Policy Act of 1992, and the more recent landmark Telecommunications Act of 1996, which deregulates or significantly reduces regulation of various telecommunications markets, there has been legislative activity at the federal level aimed at deregulation of the electric industry. On January 25, 1996, Senator Bennett Johnston introduced the Electricity Competition Act of 1996 (S.B. 1526), which proposed to bring competition and deregulation to the nation's electricity industry. The Johnston Bill would preempt significant areas of traditional state regulation of utilities, and mandate sweeping changes in the industry. The proposed legislation contains six main elements: (1) retail access for all electricity consumers by the year 2010, (2) assured stranded cost recovery, (3) shared federal and state responsibility which tracks current jurisdictional responsibilities, (4) a timetable for the transition to a competitive market, (5) reform of PURPA and PUHCA, and (6) assured recovery of costs to decommission nuclear power plants.

Another bill entitled Electric Power Competition Act of 1996 (H.R. 2929), was introduced by Representative Edward J. Markey on February 1, 1996. Less comprehensive than the Johnston bill, the proposed legislation would require either retail competition or divestiture of generation from transmission to avoid the obligation to purchase from QFs. The bill also would impose certain other conditions and standards.

Another legislative proposal, the Electric Consumers' Power to Choose Act of 1996, has been introduced by Representative Dan Schaefer, chairman of the House Commerce Energy and Power Subcommittee. In recent months Representative Schaefer has been an outspoken proponent of competition in the electric industry, arguing that the generation of electricity is no longer the natural monopoly it once was. He cites experience with long-distance and local telephone service and the natural gas industry as proof that once the notion of a natural monopoly is challenged it is only a matter of when -- not if -- competition will come. He cites four prior government actions as having failed the electric industry: PURPA locking utilities into bad contracts, the Fuel Use Act forcing utilities into nuclear power only to have the government later undermine such investments, PUHCA keeping utilities from competing, and state regulators forcing demand side management and social engineering experiments on utilities.

The stated purpose of the Schaefer proposal "*is to give all American electricity consumers the right to choose among competitive providers of electricity*...." The proposal would mandate that, by no later than December 15, 2000, all retail consumers would have the right to purchase retail electric energy services from any person offering such services. States are given six months (which can be extended if legislative activity is needed) to elect to establish choice by December 15, 2000. States electing to do so must establish rules regarding choice, access to local distribution facilities and cross-subsidization of other services with revenues from LDC facilities. If states do not elect to establish a plan, FERC is given the authority to implement such a plan.

States are also required to consider applying to the sale of retail electric energy services tariffs, surcharges, terms and conditions which: (1) ensure adequate electric service from the local distribution system; (2) ensure reliability of service; (3) provide for recovery of investment costs (i.e., stranded costs) incurred prior to July 11, 1996; and (4) promote energy efficiency, conservation and environmental programs. Only states could address the stranded cost issue. Similar provisions are made applicable to nonregulated electric utilities, which must either elect a plan or have FERC establish one.

The Schaefer bill would also bar any state or local legal requirements after December 15, 2000, which prohibit any entity from offering retail service to any retail customer. States would only be allowed to impose requirements related to universal service, protection of "*public safety and welfare*" and quality of service. The bill also addresses jurisdictional authority of states and FERC regarding transmission and distribution.

The bill would also effectively eliminate the applicability of PUHCA once retail access is established. Section 210 of PURPA would be treated similarly, but contracts in effect on July 11, 1996, would remain in effect.

The Schaefer bill would end state regulation over significant aspect of electric utility service, even in those states not interested in retail competition. It would effectively eliminate over 75 years of state jurisdiction of a service deemed critical to the well-being of individuals and businesses. It would represent a fundamental shift in state-federal relations by federalizing regulation over facilities valued at hundreds of billions of dollars which have been built and operated predominantly under state authority.

Comprehensive legislation deregulating the electric utility industry does not appear likely to be passed in 1996. Given the uncertainties that surround some fundamental issues, the vast number of investigations and experiments being conducted at the state level, the status of current dockets at FERC and the heightened political climate in an election year, final approval of a broad federal scheme for the industry does not appear imminent.

Other federal legislative proposals also have the potential to affect the industry in significant ways. Various bills have proposed sweeping changes in PURPA and PUHCA, while others would allow Amtrak to wheel power for itself and other end users (in effect, retail wheeling) and authorize certain government agencies to shop for competitive supplies of power in place of the franchised utility where the facility is located. To date, none of these legislative proposals has passed Congress.

H. Development of Futures Market

The New York Mercantile Exchange ("NYMEX") opened trading on electricity futures contracts on March 29, 1996, with two delivery locations, California-Oregon Border ("COB") and Palo Verde Nuclear Switchyard ("Palo Verde"). On April 26, 1996, options on electricity futures contracts began trading for both of these delivery points. The NYMEX electricity futures and options contracts provide a forum for interested parties to hedge against price risk associated with electricity by transferring the risk to someone willing or able to assume the risk or who may have an inverse risk profile. These interested parties may prove to be utilities looking to sell or buy electricity, independent power producers, large electricity users, or investors looking to speculate on the price of electricity.

Futures and options have different features and are useful to different types of investors. Futures contracts represent an obligation to buy or sell a commodity at a future point in time at an agreed upon price. As the "*cash price*" of the underlying commodity changes, the value of the futures contract will move in the same direction as the underlying price of the commodity (both move up or both move down). If an investor owns a futures contract (referred to as "long"), they may be hedging against a price change, i.e., they are locking in the price over the time period contained in the futures contract.

An option is the right, but not the obligation, to deliver the futures contract at the strike price, if the option is exercised. There are two types of option contracts, call options, which represent the option to buy, and put options, which represent the option to sell. Call options reflect expectations that prices will rise, while put options reflect expectations that prices will fall. As a general rule, options, as opposed to futures, represent a more highly leveraged way to participate in the electricity commodity market. For example, the value of one electricity futures contract currently is about $12,954 (736 MWh X $17.60/MWh), while the value of an option which controls the same amount of energy may cost less than $1,000. Options are primarily for seasoned players in financial markets because of their high leverage feature.

There are two NYMEX standardized electricity futures contracts with the only difference being the delivery point. The standard futures contract is for the delivery of 736 MWh of firm energy over the course of the specified delivery month. The 736 MWh are delivered at a rate of 2 MW throughout every hour of the delivery period. The delivery period consists of 23 days for 16 on-peak hours a day (2 MW X 16 hrs X 23 days = 736 MWh). These 23 days include all business days of the delivery month, Monday through Friday, excluding days designated as off-peak (mainly holidays) by the North American Reliability Council. When there are less than 23 business days then Saturdays will be delivery days, beginning with the first Saturday of the month. Futures contracts must meet the delivery standards established by the Western System Coordinating Council. Futures contracts trade for 18 consecutive months with delivery beginning in June 1996, options trade for the 12 consecutive months with delivery beginning in August 1996.

There are numerous ways in which a utility can utilize futures and options to mitigate price fluctuations in electricity. Futures contracts allow both producers and consumers of electricity to set prices to buy and sell electricity for future delivery with prices based on supply, demand, volatility and the time value of money. This type of arrangement gives the producer a guaranteed sales price and the buyer a guaranteed purchase price at some future date. Therefore, any fluctuations in price between the contract date and delivery date are mitigated with the futures contract. A utility could use a futures contract to either sell or purchase electricity and be guaranteed the price it receives or pays. The utility could also buy a futures contract on its fuel, such as oil and natural gas, in order to mitigate fluctuations in the price in the future. The fluctuation in price will be offset by the change in the value of the futures contract, therefore, eliminating the risk associated with price changes in its fuel. A utility could also use options to mitigate price changes in electricity or fuel sources. For instance, a utility can meet its incremental load needs by buying options for future delivery. If the incremental load never materializes, the utility simply lets the contract expire without exercising it and the utility only loses the cost of the contract. In fact, the Tennessee Valley Power Authority has used this approach to avoid building peaker units. It signed a series of option contracts with Enron for the delivery of up to 3,000 MW of power to be delivered between 1998 and 2002. If TVA needs the power it will exercise the option, if not, it will simply let the option expire.

Electricity futures trading volumes so far have the characteristics of newly developing markets, showing low and scattered volumes. As of the end of May 1996, weekly COB futures trading volume was about 1,200 contracts with Palo Verde only 1/4 of that volume. As a comparison, natural gas futures had daily trading of 40,000 contracts in a comparable time. Trading electricity as a commodity has the potential to become larger than the $225 billion petroleum market. Current plans are to expand the contracts to include at least one east coast delivery point early in 1997, and PJM is a likely candidate.

Exchange president R. Patrick Thompson said, "*Given the sophistication that the electricity industry is rapidly developing in market mechanisms, we believe it is appropriate to be able to offer these expanded risk management services far sooner than we were able to with any of our earlier contracts*." The previous record for option listing following futures contracts was 2 1/2 years for natural gas contracts. Participants in the natural gas futures markets have been primarily gas marketers (59%), followed by producers (13%) and speculators (11%). Utilities have not been active participants yet due to lack of regulatory guidance toward the approval of trading activity expenses or treatment of gains/losses. Examples found in the crude oil and natural gas markets suggest that initial players will be commodity producers (NUGs), and energy marketers. For the market to develop with the potential for the underlying value of electricity contracts to exceed $225 billion, as some expect, utilities and/or their energy services groups will have to be major players in the market. A survey from the third quarter of 1995 of power marketers confirms that electric utilities are not yet major players in the futures markets. Several large integrated gas utilities are major players already, as well as several large independent power producers.

While the NYMEX price is relatively new, there have been other indices established to provide a view of electricity prices. As the electric power industry has evolved in the past few years, utilities, federal power authorities, and power marketers in the western United states have joined to create the COB Index and the Palo Verde Index for wholesale electricity prices. These are regional spot indices of the prices of electricity bought and sold at the respective locations. The indices benefit participants by allowing electricity to be bought and sold more like a commodity and will help develop a more efficient market and efficient dispatch of generating facilities. The explicit pricing information provides a degree of market information that was not available before the indices were established and also have allowed for the development of financial risk-management instruments such as futures and option of futures.

Both locations, due to their interconnections and volume of transmission, are suitable delivery points from which to measure the price of electricity. The COB is actually a series of interconnections along the border of California, Oregon, and Nevada which is considered a single transaction point. The Palo Verde Switchyard is located in eastern Arizona and is associated with the Palo Verde nuclear plant. The switchyard is within the control area of the Salt River Project. These respective points form the equivalent of a trading hub. For each trading point, each day participants in the index report to Dow Jones their weighted average price for sales and mega-watt hour volume during the previous day. Dow Jones then disseminates the index through the company's information services and in The Wall Street Journal. There are indices for firm and non-firm power which are subdivided into on- and off-peak prices.

Futures and option contracts provide observers, including utilities, a view of future electricity prices. Very few futures contracts are ever taken to delivery, (less than 1% for energy) with most being liquidated and offset before expiration. However, the NYMEX electricity futures contracts provide for delivery to ensure that futures and cash-market prices converge upon expiration of the contract. This ensures that the futures contracts give a reliable indicator of cash-market prices. The development of an active electricity futures market may hasten competition in the electric industry.

I. Activities in Other States

Retail electric service in most states continues to be provided by vertically integrated utilities operating in exclusive, franchised territories subject to state law and regulatory authority. There is, however, considerable activity at the state level regarding restructuring and introduction of competition, with the majority of states investigating the issues through a formal process. Activities by states range from affirmative decisions not to investigate or implement retail wheeling, to active plans to open the retail market, to competition within a definite time frame.

The greatest movement toward restructuring and introduction of market factors comes from those jurisdictions which have the highest retail rates. Chief among these jurisdictions are California and New York where rates far above the national average have resulted from high cost nuclear plants, uneconomic NUG contracts, alternative energy programs, social programs, and other factors. A summary of activities in certain states as of early June 1996 follows.

California

Developments in California have received considerable national attention. Because of the state's lagging economy and high electric rates, California has given early consideration to industry restructuring and has taken concrete steps to replace rate-base, rate-of-return regulation with a market-oriented model for the sale of electricity. The California model represents the first major state plan to move to a competitive model from the traditional regulatory approach.

The California plan, which is directed at all major electric utilities in the state, would drastically transform the electric industry in California. By order dated December 20, 1995, and subsequently modified on January 10, 1996, the California Public Utilities Commission ("PUC") adopted a plan which seeks to accomplish the following:

- establish a statewide Independent System Operator ("ISO") on January 1, 1998, to operate California's transmission system;
- establish a statewide Regional Power Exchange on January 1, 1998, to foster and sustain the development of a spot market for the generation of electricity;
- begin the phase-in of retail wheeling on January 1, 1998, and to offer full customer choice by January, 2003;

- establish a price cap for California utilities based on established revenue requirements as of January 1, 1996;
- provide incentives for utilities to "voluntarily" divest themselves of 50 percent of their fossil generation;
- establish a "nonbypassable" transition charge to fully recover transition/stranded costs by the year 2005; and,
- preserve certain on-going societal programs in California.

The ISO will perform the daily dispatch and delivery of power across California's transmission system and will "*apply a pricing structure that supports competition and avoids cost shifting.*" The ISO will also maintain frequency control, comply with all North American Reliability Council standards, and be required to evaluate the transmission system for needed upgrades. However, the order is vague with respect to how future transmission enhancements will be made. The order indicates that the CPUC hopes that market forces will provide the principal impetus for transmission investments, but does not provide a detailed explanation of how such forces will operate or the measures to take if the market forces fail in this task.

The ISO is prohibited from having a financial interest in the regional power exchange, generating facilities or load (presumably load serving entities connected to the independent system). It is not clear from the order whether the ISO can own transmission facilities. Existing utilities will, at least initially, continue to own transmission facilities which will be controlled by the independent operator. The ISO and the power exchange will be separated to assure that bilateral contracts and pool transactions have equal transmission access.

Because of the link to transmission and wholesale transactions, the ISO and the power exchange will be subject to FERC's regulatory authority. The California utilities were directed by the California Commission to file proposals with FERC regarding the establishment of a power exchange and ISO by April 29, 1996.

The power exchange will act as a clearinghouse for generation by providing hourly or half-hourly price signals and by implementing nondiscriminatory rules which will allow generators to compete on a common basis. Beginning on January 1, 1998, utilities must bid generation to the exchange and procure energy for their customers from the exchange. Utilities are prohibited from entering into bilateral contracts during a five year transition period. Distribution utilities can purchase all or a portion of their needs from non-exchange sources after the transition period. However, distribution companies will be prohibited from entering into bilateral agreements with affiliates.

The clearinghouse price will be determined through an auction in which generators will submit bids for the minimum price required for the dispatch of specified increments of power. Winning bidders will be paid the market clearing price. The order does not include a rationale for using the "*market clearing*" price or provide any guidance with respect to "must-run" units or congestion pricing.

The order requires that the phase-in of retail wheeling be initiated by January 1, 1998, and completed by 2003. Although the order indicates that each customer class must be represented during the phased access to retail wheeling, it does not specify a means for assuring that each class is represented, minimum requirements for supply aggregators, or a method for the queuing of customers. Customers will eventually have three options pursuant to the order: (1) traditional utility service where the distribution utility will act to aggregate supplies, (2) traditional utility service with hedging contracts to assure price stability, or (3) direct access with bilateral contracts. Utilities will continue to be obligated to procure power supplies for customers who opt for the traditional utility service. Smaller customers can opt for average pricing or real-time pricing (virtual direct access) under the traditional utility service offering. Real-time metering will be mandated for larger customers based on their maximum customer demands.

The order raises a concern that there may be excessive market concentration in the electric industry and notes that a single competitor may own enough assets to alter the supply/demand equilibrium by controlling specific blocks of assets. Consequently, the order seeks to provide incentives for utility divestiture and directs California utilities to file plans to voluntarily divest at least 50 percent of their fossil generating assets. The order indicates that utilities will receive an increased return on equity of up to 10 basis points for every 10 percent of fossil generation that is divested. Utilities will be penalized by lower equity returns (10 percent below the long term cost of debt) for fossil generating assets that are not divested. The order justifies this lower return by indicating that utilities will have a greater assurance of cost recovery since these higher or lower returns will be reflected in the development of the "nonbypassable" transition charge.

The order indicates that the rates charged by California utilities will be subject to price caps based on established revenue requirements as of January 1, 1996, and creates a competitive transition charge for recovering stranded costs. It is not clear from the order whether the price cap will continue if established revenues are insufficient for the recovery of stranded costs and future utility costs. Transition costs will be accrued through the period 1998-2002, and collected through a period ending in 2004. There will be three methods for determining transition costs associated with utility owned fossil units. These methods are as follows:

1. Transition costs will be calculated by comparing actual revenue from the power pool to the calculated revenue requirement based on the net booked value of generation prior to divestiture or a market evaluation.

2. Transition costs for divested assets will be based on a comparison of the sales price of the assets to their net book values.

3. Transition costs for assets that have not been sold or spun-off will eventually be based on market valuations (appraisals) of those assets in comparison to their net booked values.

Transition costs for nuclear units will be based on some determination of the revenue requirements for those units and the pool related revenue derived from those units. In certain instances, utilities have negotiated rate settlements that will form the basis for the revenue requirements for specified nuclear units. For purchased power contracts, transition costs will be based on the difference between associated pool revenues and the prices paid pursuant to those contracts. Utilities are encouraged to renegotiate these contracts and will be allowed to flow 10 percent of any savings resulting from those negotiations directly to their stockholders. The order does not address whether or not there will be a determination of transition costs associated with nuclear units and purchased power contracts after the year 2002.

Transition costs will be allocated to the various customer classes based on traditional marginal cost allocations and will be collected through a "percent of revenue" based charge. The order does not include a detailed description of how this charge will be applied. Consequently, it is unclear whether there will be adjustments to reflect differences between customers who opt for direct access and those who continue to receive traditional services. It is unclear whether customers who opt for traditional utility service will be protected from paying higher rates because they continue to pay for traditional supply related services in addition to distribution services. Given this possibility and uncertainties associated with nuclear units and purchased power contracts, customers opting for traditional utility services may bear a disproportionate share of the cost of moving to a market driven electric industry unless adjustments are made.

The California policy promoting utility divestiture may also have an adverse impact on customers since utilities have little, if any, incentive to negotiate the best deal for selling generating assets (and thereby minimize stranded costs) and the fact that those assets will be dumped in the marketplace in a relatively short time-frame. The order's response to this concern is to require that proposed divestitures be advertised as widely as possible, but such an approach may prove insufficient in overcoming the lack of incentives and short time period for divestiture.

The order indicates that the CPUC will continue to support certain societal and environmental programs. These programs include low emission vehicles, economic development rates, underground electric lines, renewable resources, public purpose research and development, demand side management, low income assistance and special rate discounts. The order is vague with respect to how these programs will continue to be supported. For example, the order indicates that there will be ongoing targets for minimum levels of generation from renewable fuels with meaningful penalties if these targets are not met, but the order does not specify who will be subject to these penalties. Moreover, the order does not reconcile these continuing costs with lower rates for customers. Certain of the above programs may be supported by a "public goods" surcharge that would be subject to approval by the California legislature.

The California decision includes several bold and innovative approaches for electric utility restructuring. The plan will effectively end the system of vertically integrated utilities operating in franchised service territories. Unfortunately, many of the details associated with California's restructuring efforts have not been developed at this time, and some of them, such as the degree of divestiture and market structure necessary to eliminate market power in generation, are critical to developing a truly competitive market. California has obviously made the "leap of faith" required to conclude that competition is in the public interest, and, given its current high rates, there may be little risk to California ratepayers in the sweeping changes now taking place. California will likely provide the rest of the country with valuable information about the steps necessary to develop a competitive electric structure and the possible benefits and pitfalls of various approaches.

New York

New York also has some of the highest cost power in the United States. The state's 1995 average industrial rate for major electric utilities ranged from 5.81¢ to 12.92¢ per kWh. Understandably, there is considerable interest and activity in New York regarding wholesale and retail wheeling of electric power.

On July 11, 1994, the New York Public Service Commission ("NYPSC") issued findings stating its belief that competition currently exists and will likely increase, predominantly in upstate New York. As such, the NYPSC instituted a generic proceeding in which the parties were directed to examine both wholesale and retail wheeling models for electric restructuring and to file summaries of different industry structures. Participation in the generic proceeding has been diverse, including electric utilities, industrials, various power authorities, and consumer groups.

On May 16, 1996, the NYPSC approved an aggressive statewide restructuring plan that calls for wholesale competition to begin in early 1997 and retail access to begin in early 1998. The order states that stranded costs will be dealt with on a utility-by-utility basis. All utilities, with the exception of Niagara Mohawk Power Corporation ("NiMo") and Long Island Lighting Company ("LILCO") are required to file rate and restructuring plans by October 1, 1996. Stranded cost recovery will be addressed in these filings.

NiMo is exempt from the filing requirements, as its proposal for reshaping itself and for restructuring the electric utility industry is currently pending before the NYPSC. LILCO is also exempt as it is currently engaged in negotiations with the Long Island Power Authority ("LIPA") regarding structural issues.

NiMo filed its proposal for reshaping itself and for restructuring the New York electric utility industry on October 6, 1995. The proposal, called Power Choice, was filed with the NYPSC in the context of a negotiated rate case. NiMo recommends splitting the corporation into two units, separating generation from all other utility functions. The generating company ("Genco") would consist of all of NiMo's generating facilities, including nuclear plants, and non-utility generator contracts. NiMo's non-utility business and assets would be placed under an unregulated holding company.

Under the proposed plan, NiMo's Genco and other companies would compete in a bulk power market that would be coordinated by an independent system operator and supervised by FERC. NiMo would allow retail access to the generation market in their service territory as soon as technically and administratively feasible. Phase-in of the proposal is projected to start as early as January 1, 1997, and to be completed by January 1, 2000. NiMo also proposes an immediate rate reduction for industrial customers and a five-year rate freeze for residential and commercial customers.

As part of Power Choice, NiMo requests that the New York Power Authority ("NYPA") participate in a competitive restructuring of the market by financing NiMo's purchase of unregulated generators' units, through negotiation or eminent domain. The trade association of Independent Power Producers of New York protests that NiMo does not have the legal authority to either extinguish their contracts or seize IPP facilities through the power of eminent domain. Another section in Power Choice proposes that the NYPA could contribute to resolution of NiMo's overall stranded cost issues by refinancing the company's nuclear units or buying them. Independent observers believe NYPA has little motivation to purchase the company's nuclear plants.

On December 5, 1995, LIPA released its Technical Report recommending the sale of LILCO's generation assets to third parties and then a takeover by LIPA of LILCO's transmission and distribution ("T&D") system. Under the recommended approach LIPA would become a "wire company" which would purchase, transmit, and distribute electricity from generators to retail customers, but would contract out management of the system. T&D financing would be provided by LIPA-issued tax-exempt bonds, though there is some concern over "private use" restrictions on tax-exempt bonds issued for the benefit of a private trade or business.

The report, which was prepared pursuant to the governor's mandate to the LIPA board, recommends that the change should occur as a negotiated transaction between LILCO and LIPA. If negotiations fail, LIPA would exercise the power of eminent domain over all or a portion of LILCO's assets for the purpose of selling the company's fossil generation, selling the company's gas distribution system to a private owner, and acquiring the company's electric transmission and distribution system.

In addition, the NYPSC currently has pending before it five pilot programs for retail wheeling. One pilot for Orange & Rockland Utilities ("O&R") has been approved and began in July 1996. The pilot called "Power Pick" is divided into two parts. One part is for the Industrial Energy Users Association, a large group of O&R's largest industrial customers. The second part of the pilot begins January 1, 1997, and will extend the program to small commercial and industrial customers and about 1,500 residential customers.

Massachusetts

Massachusetts, like New York and California, has relatively high electric rates. For example, the state's 1995 average industrial electric rates for major electric utilities ranged from 7.68¢ to 9.74¢ per kWh. It is not surprising, therefore, that on May 1, 1996, the Massachusetts Department of Public Utilities ("MDPU") issued proposed rules for restructuring the electric industry that in some details resembles the California approach. The MDPU said its version of a restructured electric industry includes: an ISO, possibly evolving from the New England Power Pool; a power exchange; functional separation of electric companies into generation, transmission, and distribution corporate entities; and a "*reasonable opportunity*" for recovery of stranded costs. The proposed rules also offer options for phased incentives for electric companies to divest their generation assets in hopes that this will stimulate a robust competitive market. Other provisions address support for energy efficiency and renewable energy resources and a "*price-cap system of economic incentive regulation for the remaining distribution and transmission monopoly*." Finally, by January 1, 1997, utilities would have to unbundle rates on their bills into separate components including transmission, distribution, and a "*market proxy for energy costs*." The MDPU states that its final regulations should become effective in October 1996, and implementation of a competitive generation market should occur in Massachusetts by January 1, 1998.

The MDPU also has pending before it the restructuring plan of the New England Electric System ("NEES"), which was filed on February 16, 1996, with the MDPU, the Rhode Island PUC, and the New Hampshire PUC. The NEES proposal calls for direct access by January 1, 1998, for all customer classes in Massachusetts, Rhode Island, and New Hampshire. NEES also recommends unbundled rates; competitive generation; a monopoly transmission and distribution system; performance-based pricing for distribution services; functional separation of generation, transmission, and distribution; a uniform wires charge to cover transition costs; and a wires charge to cover energy efficiency and low income programs. The proposal was still pending before the MDPU as of June 1996.

On September 29, 1995, the MDPU approved Cambridge Electric Light Company's ("CELCO") tariff filing, which provides for the recovery of 75% of the company's net stranded costs due to the departure of one of their largest customers, the Massachusetts Institute of Technology ("MIT"). MIT built an on-site cogeneration plant and will no longer require full service from CELCO. The MDPU has said the decision to approve the transition cost tariff is limited to this one case, is not precedent setting, and will only apply until August 16, 1996, when CELCO files its restructuring plan with the MDPU. The new transition cost tariff will only be paid by the customer leaving the system, MIT, which represents about 10% of CELCO's load. MIT has argued that its on-site generation plant has nothing to do with restructuring and that the transition cost tariff is inconsistent with and preempted by PURPA. MIT further argues that the transition cost tariff would be in direct conflict with PURPA objectives to promote alternative energy and would violate FERC regulations that require utilities to provide nondiscriminatory, cost-based standby and maintenance services to qualifying facilities. While PURPA is silent on the issue of stranded costs, the MDPU approved the transmission cost tariff for the newly created "*load at risk*" customer class because they believe it will balance the interests of MIT, the utility, and remaining full service customers.

Vermont

In Vermont, the 1995 average industrial electricity rate for the state's major electric utility was 7.8¢ per kWh. The Vermont Public Service Board ("VPSB"), in an October 17, 1995 order, stated that its goal is to produce a policy framework for industry restructuring through rules and proposals to its legislature. The order further states that the VPSB agrees with the Vermont Department of Public Service's goal of achieving a restructured electric industry in Vermont by December 31, 1997, but cautions that there may be factors that restrain the pace of activities in that regard.

Various utilities, including Green Mountain Power and Central Vermont Public Service, have filed their restructuring proposals with the VPSB. All parties to the restructuring docket are to file recommendations with the VPSB by early June 1996. After conducting hearings, the VPSB plans to issue a draft report in August 1996 outlining the legislative and VPSB action required to implement restructuring. The VPSB will take comments on its draft report and plans to issue a final report in November 1996.

Illinois

In Illinois, the 1995 average industrial electricity rate for major electric utilities ranged from 3.77¢ to 6.00¢ per kWh. On May 21, 1995, the Illinois legislature established the Joint Committee on Regulatory Reform to investigate competition-related issues. It is anticipated that further legislation will be introduced in the 1997 session. On September 20, 1995, Central Illinois Public Service Company ("CIPSCO") submitted to the joint committee a two-phased retail access plan, which includes provisions for the recovery of stranded costs. On February 9, 1996, the Illinois Commerce Commission's ("ICC") Chairman Miller proposed "*the safe zone plan*," in which electric rates would be capped during a five-year mitigation period, after which customer choice, open access and retail wheeling would begin. The joint committee's final legislative proposal on restructuring is due on or before November 8, 1996.

Meanwhile the ICC has approved two retail wheeling pilot programs, one for Illinois Power Company ("Illinois Power") and one for Central Illinois Light Company ("CILCO"). The Illinois Power retail pilot program is offering a maximum of 50 MW of Direct Energy Access Service ("DEAS") capacity to approximately 20 of Illinois Power's largest customers. For purposes of the DEAS program, the ICC approved the use of the charges and other terms and conditions for transmission and ancillary services in Illinois Power's FERC approved open access tariff. DEAS will be offered until December 31, 1999, so long as at least eight customers and 30 MW of load remain on the tariff. DEAS customers will be responsible for procuring their own capacity and energy supplies from third parties, as well as any transmission over intervening systems necessary to reach the Illinois Power control area interconnection point. DEAS load may not be served on Illinois Power sales, service, tariffs, or contracts, and the utility will have no obligation to serve DEAS load except in accordance with ancillary services purchased by the customer. Illinois Power estimates a net annual revenue loss of $3.1 million to $7.5 million from load moving to DEAS, not including any revenue the utility may obtain from selling capacity and energy formerly used to serve DEAS customers. The company is not seeking to recover this lost revenue from nonparticipating customers.

CILCO has two approved pilots. One that is available for up to five years to any and all customers including residentials, commercials, and industrials located in one or more designated "*open access sites*," which will be determined by CILCO. Residential customers will be required to purchase all of their capacity off-system due to their small usage and lack of time-of-use demand meters. For all other participants, there will be no minimum or maximum purchase requirements. Customers can withdraw from participation on 24 hours notice, but then must wait 90 days to participate again.

The second pilot would be available for two years to industrial customers with peak loads of 10 MW or more to purchase some or all of their power needs from other suppliers, up to an aggregate total of 50 MW. CILCO's eight largest customers would be eligible for the pilot. Customers who choose to participate must pay for the contracted capacity whether or not it is actually used for delivery of their off-system purchases. Any usage by participating customers that is not purchased off-system will be supplied by CILCO under its otherwise applicable rates with one exception. During capacity-deficient periods, participants who do not use all of their contracted capacity for delivery of off-system purchases must pay a supplier-short-fall charge of 10 cents per kWh for usage up to contracted capacity. This exception is intended to prevent participants from returning to CILCO's system during periods when fuel prices are high to the disadvantage of other customers.

CILCO expects reduced purchases and a potential loss of up to $3.1 million to $4 million per year in net income resulting from its 2 year experiment. No estimate of expected lost income was offered for the 5 year experiment. CILCO states that its shareholders will absorb these losses.

New Hampshire

In New Hampshire, the 1995 average industrial electricity rate for major electric utilities ranged from 7.71¢ to 8.97¢ per kWh. New Hampshire has been very active on the restructuring front. During its 1996 session, the New Hampshire legislature passed legislation authorizing the New Hampshire Public Utilities Commission ("NHPUC") to require utilities to implement retail wheeling for all customer classes at the earliest date the NHPUC determines retail wheeling to be in the public interest. The bill requires utilities to file restructuring plans with the NHPUC by June 30, 1996, and to obtain NHPUC approval by June 30, 1997. If a utility fails to receive NHPUC approval by this date, the bill authorizes the NHPUC to adopt a restructuring plan for the utility.

Under legislative mandate, the NHPUC has implemented a two-year retail wheeling pilot program which began May 28, 1996. Under the retail wheeling pilot program, 3% of each utility's peak load -- approximately 60 MW total -- will be opened to competitive suppliers. The NHPUC will select customers at random. Customers will include representatives from the residential, commercial, and industrial classes. The NHPUC states that the pilot is not intended as an endorsement of retail wheeling, but as an opportunity to study it in a controlled setting. While the NHPUC proposed that utilities recover 50% of stranded costs from participating customers with utility shareholders paying the rest, the NHPUC approved implementation plans that its staff negotiated separately for each utility. These plans allow companies to charge rates for delivery services that would effectively recover greater than 50 percent of anticipated stranded costs. The rates that utilities may charge retail wheeling customers for the delivery of power from competitive power suppliers do not include an explicit stranded cost charge, however, utility stranded costs can be imputed from the allowed delivery service or access charge revenue streams and utility costs incurred in connection with implementing the pilot. Public Service of New Hampshire ("PSNH") has said that under its approved implementation plan and compliance tariff, it expects to recover all of the direct and stranded costs it anticipates it will incur in implementing the pilot.

In May 1996, the New Hampshire Supreme Court affirmed the NHPUC's June 1995 ruling that utility franchises are not exclusive under New Hampshire law. The court held that the plain language of the state's franchise statute both authorizes and requires the NHPUC to grant a competing franchise when that would be "*for the public good*." This holding resolves a threshold issue in the ongoing dispute between PSNH and Freedom Electric Company ("Freedom"), but there are other aspects of the case before the NHPUC to be resolved before Freedom may begin electric operations. The NHPUC has yet to decide whether to permit Freedom to operate as a public utility in New Hampshire.

Michigan

In Michigan, the 1995 average industrial electricity rate for major electric utilities ranged from 3.02¢ to 5.43¢ per kilowatt hour. In April of 1994, the Michigan Public Service Commission ("Michigan Commission") ordered limited retail wheeling as part of an experiment with restructuring the electric utility industry. The pilot approach was taken to determine the benefits of retail wheeling, if any, before a large scale proposal is issued. On June 19, 1995, the Michigan Commission set rates and charges for retail delivery service for their five-year experimental retail wheeling program for the Detroit Edison Company and Consumers Power Company, setting aside for direct access 90 MW for Detroit Edison and 60 MW for Consumers Power. The program is contingent upon the utilities filing resource plans that call for new capacity and will be initiated at the next solicitation of new capacity, which is not anticipated for several years.

Detroit Edison, Consumers Power and others have made a consolidated appeal with the Michigan Court of Appeals challenging the Michigan Commission's final order mandating the retail wheeling experiment. All briefings have been completed. The next procedural step is to schedule oral arguments, which are expected to take place sometime next year. Detroit Edison also filed a complaint in the U.S. District Court asserting that the initiative violates the U.S. Constitution's premises, commerce, and contract clauses, as well as due process and equal protection. On May 8, 1995, the U.S. District Court for the Western District of Michigan dismissed Detroit Edison's appeal of the retail wheeling order.

Michigan Governor John Englar issued his own industry restructuring proposal in January 1996, that would allow retail wheeling for new industrial customers within a year. The recommendation from a specially appointed committee to the Michigan Commission has three phases. In the near term, by January 1, 1997, new industrial and commercial load could negotiate directly with generators and be wheeled over common transmission lines. In the intermediate term, by January 1, 1997, an independent wholesale electric pool would be created. In the long term, by January 1, 2001, industrial and commercial rate classes would be allowed to aggregate their demand, purchase retail electricity, negotiate bilateral agreements, or buy wholesale power. On April 12, 1996, the Commission ordered Detroit Edison and Consumer Power to file "*applications*" by May 15, 1996, addressing the Governor's recommendation to permit all new industrial and commercial electric load to be supplied through direct access arrangements effective January 1, 1997.

In addition, currently under Michigan Commission review is Consumers Power's settlement with the MPSC staff to implement a "*limited direct access*" program. Along with other special tariff and contract provisions, the agreement allows the customers of Consumers Power with over 3 MWs of load to purchase power from an independent power producer or qualifying facility within its service territory. The proposal was reached and filed in connection with the utility's pending rate, special competitive services tariff, and depreciation cases.

Wisconsin

In Wisconsin, the electric rates for industrials range from 3.24¢ to 5.37¢ per kilowatt hour. On December 19, 1995, the Wisconsin Public Service Commission ("WPSC") issued a work plan detailing 32 steps that must be taken before introducing retail wheeling. The phased-in approach concludes with proposing full customer choice by the year 2000, with an independent system operator and an open access transmission network for the state. It was also proposed that utilities investigate pricing mechanisms to fund renewables and energy efficiency program. The report was based on the earlier environmental impact statement, a report from the advisory committee created by the WPSC to study restructuring, and a number of public hearings. On February 22, 1996, the WPSC submitted a report to the legislature that contained implementation details regarding the December work plan.

States Bordering Virginia

The states bordering Virginia have relatively low industrial electric rates. As of early June 1996, neither the legislatures, public utility commissions nor the public utilities of these states have taken any steps toward the implementation of retail wheeling. In August 1995, the Maryland Public Service Commission issued a final order in its generic inquiry on the state's electric industry concluding that retail wheeling is not in the public interest at this time. North Carolina has required its electric utilities to file reports outlining the actions they will take to implement FERC's Order 888 and describing where they see the electric industry in the future. There has been no activity in Tennessee, West Virginia, or

Kentucky regarding restructuring.

A summary of activity in all states prepared by the Edison Electric Institute can be found in Appendix IV.

J. Utility Responses to Increased Competition

Throughout the country electric utilities have been altering their methods of operation in response to the increasing push for competition. The threat of competitors acquiring wholesale, and perhaps retail, customers has precipitated an unprecedented response from electric utilities, including cost cutting, discounts, mergers, entering new businesses and reorganizations. In the next chapter we will detail the restructuring efforts of Virginia's electric utilities. In this section we will provide examples of recent actions by utilities in other states. Only a few illustrations have been selected to show it is a wide-spread trend; a comprehensive list of utility responses to competition would be too voluminous to report.

<u>Cost Cutting</u>

Practically every U.S. electric utility has either announced or undergone a significant reduction in work force. These "downsizings" have been particularly visible in states that have high-cost power and have moved closer to deregulating their electric markets. For instance, Boston Edison has cut its staff by about 12% and reorganized its units in a marketing structure intended to be more responsive to customers. In 1990, Boston Edison had 4,800 employees and the latest cuts brought that number down to 3,500. Central Maine Power felt competitive pressures earlier than most electric utilities because of its high rates brought on in part by high-cost NUG contracts. By the beginning of 1995 it had cut its work force by 10%, cut its dividend and trimmed its capital spending.

Electric utilities have also cut their capital expenditures in an attempt to improve cash flow and increase pricing flexibility. The Edison Electric Institute conducted a survey of construction plans by U.S. utilities for 1995 to 1997. The survey forecast a 12.6% decrease in spending as compared to the 1994 to 1996 forecast.

The efforts to control costs at nuclear plants has brought charges that utilities are cutting corners on safety. This has created a problem for Northeast Utilities, which has seen its Millstone nuclear plant shut down by the Nuclear Regulatory Commission to investigate allegations that a "*new lightfootedness at Northeast*" led to safety violations.

Other forms of cost cutting have included dividend reductions and asset write-offs. For instance, in 1995 Texas Utilities cut its quarterly dividend from $.77 to $.50 and wrote off $802 million in assets to prepare for competition.

<u>Customer Discounts</u>

A portion of the savings from cost cutting maneuvers have been passed on to customers in the form of reduced rates. These reductions frequently are in the form of discounts to large customers. A utility will often offer a discount through a contract that ties that customer to the utility for a number of years. The customer gets a guaranteed lower rate and the utility will be able to count on supplying the customer for the duration of the contract. One of the first discount contracts was between Detroit Edison and the Big Three automakers. Signed in early 1995, the ten-year contract could reduce the automakers electric bills by $400 million over the life of the deal.

Another early contract discount was between Motorola and Commonwealth Edison. Motorola was building a large plant in Harvard, Illinois, which was supplied by high-cost Commonwealth Edison. Motorola threatened to build a transmission line to a cheaper power source at a Wisconsin utility eight miles away. Commonwealth Edison cut its rates to prevent the legal actions and corporate ill will that might result from contesting Motorola.

Central Maine Power, earlier mentioned as a cost cutter, worked out an accord to cut its larger customers' rates for five years. These customers represented a third of Central Maine's sales. Champion Paper, one of the customers, was about to install a 40 MW generator, but it stopped its plans with the discount. Central Maine will see lower annual revenues of approximately $28 million because of the reduced rates.

PECO Energy negotiated lower rates for the city government of Philadelphia and its school district. PECO will give an 8.65% discount for four years with optional renewals at even lower rates. The total savings over four years could be $30 million.

Nevada Power plans to file with its state regulators for permission to reduce rates for its large customers. Mirage Resorts has threatened to build its own generators unless it gets reduced rates.

The push by large customers for reductions in rates is continuing. It is especially prevalent in high-cost states and in areas where regional price variations are large. Consumer advocates fear that if there is a transition from a regulated monopoly industry to retail competition, the large customers will abandon high-cost utilities and make deals that allow them to escape transition charges associated with stranded costs.

Energy Services Business

Many electric utilities have broadened their focus from the provision of electricity to the provision of a comprehensive package of energy services. The potential option of customers to buy power from another supplier presents both a threat and an opportunity for electric utilities. The threat, of course, is that they may lose some existing customers. By offering a broader array of services to existing customers, particularly industrial customers, utilities hope to strengthen loyalties that may have developed after decades of service. The opportunity derives from the ability to steal customers from other utilities. It is not uncommon for utility subsidiaries to open offices in service territories of other utilities offering energy services now with the hope of providing electricity to these new customers in the future.

In the next chapter we will provide examples of some of the energy services activities of Virginia's electric utilities in a discussion of their restructuring efforts. Here we identify recent announcements from across the country which demonstrate the pervasiveness of the development of energy services businesses and the types of service offerings available to large electric users.

Duke Energy Corporation's Duke/Louis Dreyfus LLC subsidiary has joined with Lykes Energy Inc. to form a company that will provide energy services to both wholesale and retail customers in Florida. It will offer electric and fuels marketing, energy systems engineering and design, and fuel procurement. It also will own or lease generating facilities and operate them.

Green Mountain Power has joined with Hydro-Quebec, Consolidated Natural Gas and Noverco, Inc. to form Green Mountain Energy Partners to compete in the retail energy market. It claims the combined strength of the four companies will ensure it to be a reliable supplier and powerful competitor. It has targeted New Hampshire's pilot program, described earlier, as its first market.

Illinova Corporation has formed a new subsidiary that will offer energy services across the country. It will focus initially on selling energy to bulk purchasers of electricity and natural gas in the West. An official with Illinova Energy Partners has stated, "*We will differentiate ourselves from others by how we provide value to our customers, not solely on what we provide them*."

A unit of the Southern Company called Southern Electric International plans to open offices in Boston and Concord, New Hampshire to allow it to participate more effectively in the Northeast. Southern Electric develops, builds, owns and operates production and delivery facilities. It also provides a broad range of technical services to utilities and industrial users.

Wisconsin Energy Corporation has announced an agreement with CellNet Data Systems to provide information systems that allow utilities to offer new energy management services to customers.

The list of new companies and new alliances that have formed to provide energy services businesses is long. These entities have their sights on all regions. Not surprisingly, the states that have the most aggressive restructuring plans seem to have the most activity at this time.

Mergers and Acquisitions

Another form of recent electric utility activity has been a flurry of announced mergers or acquisitions. Whereas the cost cutting, customer discount and energy services tactics of utilities are aimed toward pricing flexibility and customer maintenance, mergers and acquisitions have the tendency to create market power. For this reason, these proposals receive scrutiny for anti-trust implications.

Since the passage of EPAct, eighteen mergers have either been consummated or proposed. As with other deregulated industries, market forces replace regulatory oversight in major respects, and the S&L crisis and airline bankruptcies remind us that market forces can separate winners and losers.

In the electric industry, several large mergers announced to date have been between two equally financially healthy firms, such as the proposed merger between Northern States Power and Wisconsin Energy. These types of mergers are called "mergers of equals" ("MOE"). Characteristics of MOEs include similar size, management succession plans, an even division of board representation, and little or no shareholder premium.

FERC has recently promoted open access transmission tariffs as a way to break market power in the transmission of electricity. Critics point out, however, that mergers between utilities could create market power and cause more harm than good. The benefits which most utilities cite when requesting merger approval include the following: a larger customer base over which to spread fixed costs; cost efficiencies in labor, fuel and supplies; capacity deferrals; diversity of assets, customers, and regulation; and strategic positioning to enhance competitive position. However, it should be noted that economies of scale derived from merging seem to diminish at 1 or 2 million customers. Therefore, there may be other reasons why utility executives are pushing mergers. For example, management's desire to control its own destiny is one factor which may underlie mergers in general. Whether the reason is "bigger is better" or "devour or be eaten," utility managers may be looking out for themselves first, shareholders second. Diversification is another justification offered for mergers, based on the argument that by diversifying a utility can increase the overall return to shareholders. Generally speaking, this has not proven to be the case. In fact, many utilities have diversified in hopes of higher returns with disastrous results. It might be wise if utility executives heed efficient market theories that argue diversification is better done by the investors within their own diverse investment portfolios, rather than by the utility for the investors.

A study of 12 large electric utility mergers revealed that major savings came from reduced staffing (41%), elimination of duplicative corporate programs (17%), capacity deferrals (15%), and generation mix (15%). While the absolute amount of savings seems large (hundreds of millions to more than two billion dollars over a ten year period), they represent less than 3% of total utility revenues. Due to the geographic nature of electric generation and field operations, only 26%-35% of a combined company's expenses have an opportunity to be reduced. It does, however, appear that a merger quickly creates a corporate culture conducive to painful head-count reduction. In evaluating the advantages and disadvantages of mergers, one must question whether mergers are worthwhile when, according to S&P, the vast bulk of these savings could be accomplished absent a merger by managerial initiative to control costs and by forming generation or transmission alliances. This is even more pronounced in light of the market and regulatory forces pushing for the disaggregation of the vertically integrated utility. Moreover, in many mergers, other than takeovers of failed firms, it is the targeted company's shareholders who receive most of the rewards, usually in the form of a premium above the market value for their shares of stock.

Some mergers have occurred only at the parent company level, while the distribution systems remain separate and distinct utilities; thus, other benefits from mergers are hard to realize because of the difficulty in implementing the consolidation of merging partners. PUHCA-registered holding companies are restricted to operating in only one line of business; in other words, they may not own both electric and gas utilities in a holding company structure. However, recent liberalization of the 1935 Act proposed by the SEC may reduce PUHCA's constraints on mergers.

Mergers involving utilities typically need FERC approval as well as the approval of multiple state public utility commissions. Section 203 of the Federal Power Act sets FERC's role in approving mergers. This section prohibits utilities which fall under FERC jurisdiction from selling their facilities, or any asset worth more than $50,000, without prior FERC approval. FERC must, however, approve a merger if it is found to be "*consistent with the public interest*." As FERC Commissioner Massey stated, "*This is, frankly, not a very high standard*."

In analyzing whether a merger proposal is consistent with the public interest, FERC considers six factors. These factors were contained in the 1966 decision involving Commonwealth Edison Company and they include (but are not limited to) (1) measurable economic operating efficiencies (savings), (2) appropriate accounting treatments, (3) reasonable purchase price, (4) absence of coercion between parties, (5) effect of the merger on existing competitive position, and (6) ability to effectively regulate the consolidated company at state and federal levels. In most instances where there was a demonstration of cost savings and the utility offset competitive harms by offering open access transmission tariffs to others, the merger was approved.

The FERC approval process was developed in an environment dominated by regulation, not competition. However, as a result of federal legislation such as PURPA and EPAct and FERC Order 888, these standards are undergoing a significant re-evaluation. On January 31, 1996, FERC issued a Notice of Inquiry concerning its merger policy under the FPA. It is widely anticipated that any new standards promulgated by FERC concerning the evaluation of mergers will be similar to those used by the Department of Justice and the Federal Trade Commission. These standards are based on evaluating the concentration of market power which may allow sellers to collude to set higher prices and earn higher returns.

Results from past mergers provide some insight as to their overall benefit to the public. Achieved savings typically exceed original estimates, which may be a result of setting a low and easily achieved threshold. Often a condition that state regulators require for approval of a merger is a rate reduction or a rate increase moratorium for several years. Various sharing schemes between shareholders and ratepayers have been proposed and approved, but they generally give the first slice of savings to ratepayers. Regulatory treatment of the sharing of savings can affect the market's assessment of the success of a merger as evidenced by PacifiCorp's acquisition of Utah Power & Light in 1988. PacifiCorp's revenues and earnings fell after the merger, primarily because rate reductions were granted in anticipation of merger related savings which did not fully materialize.

Summary

The recent mergers and acquisition activity, cost cutting efforts, customer discounts and creation of energy services businesses are examples of utility executives making strategic decisions to meet competitive pressures. There have been dramatic changes in the industry in the past five years that likely would impede a return to the traditional electric industry even if that was considered appropriate.