Power Plant Regulatory and Policy Issues

In addition to scientific and technological advances, the regulatory and policy issues affecting power plants are changing. New developments in nuclear power regulation, competition in the electric industry, and consideration of environmental externalities will have significant consequences in Maryland.

Overview of Current Nuclear Power Issues

A substantial portion of Maryland's electricity generation (28% in 1993) is provided by nuclear power. The issues faced currently by the commercial nuclear power industry that have environmental implications fall into two broad areas: plant licensing and radioactive waste disposal. The issues involve both technical considerations and public perception.

Plant Licensing Issues

Plant License Renewal

Nuclear power plants have an operating license issued by the U.S. Nuclear Regulatory Commission (NRC) for a period of 40 years. Several utilities have expressed a desire to continue operating their nuclear power plants beyond the license expiration date for purposes of economic electric power production. The NRC must approve the application for extended operation, and issue license renewals, which may provide up to an additional 20 years of operation. The NRC will review the design and operating history of the plant prior to making a determination of continued operation. Age-management programs and maintenance effectiveness will be a large component of the NRC review for license renewal.

The license renewal of nuclear power plants has not progressed as expected by the NRC or the nuclear power industry. The two nuclear power plants in the United States which were to have served as pilots for a revamped plant license renewal process, the Monticello and Yankee plants, are no longer participating in the program. Several other plants have investigated license renewal, but have since withdrawn interest in pursuing the process. This is based on unclear requirements and the perception that a significant effort would be required to address the current regulations on investigating and managing aging mechanisms.

The NRC has published a proposed rule (in 56 Federal Register 47016, September 17, 1991) regarding the environmental review of plants that are seeking renewal of their operating licenses. The proposed rule generated significant public and governmental response, particularly in reference to the use of a Generic

Environmental Impact Statement (GEIS) for license renewal. The NRC modified its proposed rule in April 1993 to address several areas of concern. The modifications included provisions requiring a supplemental site-specific Environmental Impact Statement (EIS), rather than an environmental assessment. The GEIS will not include conditional cost-benefit conclusions. Conclusions will be made in the site-specific EIS.

The NRC is also working with states to clarify the states' authority to determine the need for generating capacity, the use of alternative energy sources, and the economics and cost-benefit balancing. These topics are covered in the GEIS, and several states had commented that it appeared that the NRC was encroaching on the states' authority in these areas by their appearance in the GEIS.

Another recent NRC action that should clarify the license renewal process is the **Maintenance Rule**, which will become effective for all existing nuclear plants on July 10, 1996. The NRC has indicated that it will evaluate license renewal applications, in part, on the basis of how well the plant is complying with the Maintenance Rule. Utilities will be required to develop equipment and plant performance goals, to monitor whether the goals are met, and to report results to the NRC. The scope of equipment subject to the rule includes safety-related components as well as any equipment that could cause a reactor "trip."

Calvert Cliffs Nuclear Power Plant, Maryland's only nuclear generating station, has implemented a Life Cycle Management program, designed to reduce costs, improve plant reliability, and comply with the Maintenance Rule. While BGE has not formally announced its intention to seek license renewal, it is well positioned and expected to do so.

Cost Beneficial Licensing Actions

Even as the NRC has established the Maintenance Rule, imposing additional requirements on nuclear plants, it is also providing opportunities for plants to reduce their regulatory and economic burden in ways that will not jeopardize safety. The NRC has recognized that some commitments that licensees have made are expensive to implement, while not yielding increases in the level of plant safety. Therefore, the NRC has invited licensees to petition for relief from such "marginal" commitments.

Another area where the NRC is allowing burden reduction involves quality assurance (QA) programs. Nuclear power plants are licensed to operate with QA programs that meet certain federal requirements. Based on operating experience, it is now recognized that all components installed in the plants do not require the same level of quality assurance. To reduce the cost burden on these components, the NRC is evaluating a graded QA program based on safety significance and risk.

Radioactive Waste Disposal

High-Level Waste

Spent fuel from operating nuclear reactors constitutes the bulk of civilian high-level radioactive waste. Operating reactors use up approximately one-third of their fuel each operating cycle (ranging from one to two years). This spent fuel is stored on-site in large water-filled tanks to cool the material and allow the radioactivity to decay. Most reactor plants built prior to 1980 do not have sufficient space in their spent fuel pools to store all of the fuel discharged over the life of the plant.

These plants can fit more fuel into the spent fuel pools by "re-racking" or placing a higher density of fuel in the existing pools. This process involves placing neutron-absorbing material in the spent fuel racks and redesigning the racks for added loads. However, most plants cannot create all the additional spent fuel capacity they need by re-racking.

In the 1960s and 1970s, the nuclear power industry anticipated being able to reprocess spent fuel into new fuel for use in nuclear plants. President Carter removed spent fuel reprocessing as an option due to concerns about plutonium diversion for nuclear weapons use. In 1980, Congress passed the Nuclear Waste Policy Act, which mandated construction of a government-sponsored high-level waste repository. The Act required DOE to take title and possession of spent fuel from nuclear power plants by 1998.

Since that time, DOE has taken the position that, in the absence of an operating high-level waste repository, the federal government has no responsibility to take possession of spent fuel. This dispute is now being argued in federal court. Under current schedules for the repository, planned for Yucca Mountain, Nevada, operations will not commence until at least 2010, leaving more than a 12-year gap that must be bridged. Options for utilities are limited. They can, as previously discussed, re-rack their spent fuel pools; some utilities (e.g., Duke Power) can transship spent fuel between sites; or they can develop alternative at-reactor storage in dry, shielded containers. On-site dry storage, the option selected by BGE for Calvert Cliffs, is discussed further in the following paragraphs.

In order to construct a dry storage facility, a utility must apply for NRC approval of the plan. NRC regulations provide two options for licensing a dry spent fuel storage facility: Specific and General. In the specific licensing approach, the applicant must provide information on the design, manufacture, and construction of the storage facility, as well as on its siting and site-specific operation. Nuclear plants that currently have licenses for on-site spent fuel facilities, including Calvert Cliffs, had to follow this procedure.

At Calvert Cliffs, 48 modules of the storage facility have already been constructed, and BGE has begun loading spent fuel into the facilities. The ultimate design approved by the NRC, which calls for 120 modules, will provide adequate storage for the remainder of the plant's currently licensed operating life. If the plant's operating life is extended through license renewal, additional storage capacity will be needed.

NRC regulations also provide a general license option, which allows a power plant operator to select a storage cask design from a list of NRC-approved systems. The licensee is responsible for reviewing the Safety Analysis Report (SAR) issued for the storage cask, and ensuring that the construction and operation of the storage facility are consistent with the limitations identified in the SAR.

It is anticipated that future applicants for dry storage will seek a general license. This is primarily due to the increasing number and variety of storage casks that the NRC has approved, and the reduction in licensing complexity in using the general license provisions as compared to obtaining a specific license. As of December 1994, there are seven storage cask designs on the NRC's list of approved systems that may be used under a general license.

Low-Level Waste

Nuclear power plants generate low-level radioactive waste in the form of contaminated equipment, spent resins, filter sludge, and other materials. The disposal of low-level waste (LLW) from nuclear reactors, as well as from medical sources and other private firms, is now the responsibility of the states. To address the LLW issue, 42 states have formed 9 compacts, which are groups of states working together to site low-level radioactive waste disposal facilities. Only two compacts operate active LLW disposal facilities, the Northwest Compact (Hanford, Washington) and the Southeast Compact (Barnwell, South Carolina). No independent states (i.e., those not participating in a compact) operate any LLW disposal facilities, and no new disposal facilities have been sited and licensed in the United States during the last 20 years. Generators of low-level waste outside the Northwest and Southeast Compacts must store their waste on site until disposal facilities are operational for their states. Many people expect that the new Republican-led Congress will take on both high- and low-level waste legislation as a higher priority item than past Congressional sessions.

The eight states that have not joined compacts are Maine, Massachusetts, Michigan, New Hampshire, New York, Rhode Island, Texas, and Vermont. It is possible that Maine, Texas, and Vermont will form a compact, with Texas being the host state for a disposal facility, but the states have not yet reached an agreement. The existing compacts are listed in Table 5-1.

Table 5-1 Compacts Formed Between States to Site Low-Level Radioactive Waste Disposal Facilities

Compact	States	Host State
Northwest	Alaska, Hawaii, Idaho, Montana, Oregon, Utah, Washington	Washington
Southwestern	Arizona, California, North Dakota, South Dakota	California
Rocky Mountain	Colorado, Nevada, New Mexico, Wyoming	*
Central Interstate	Arkansas, Kansas, Louisiana, Nebraska, Oklahoma	Nebraska
Midwest	Indiana, Iowa, Minnesota, Missouri, Ohio, Wisconsin	Ohio
Central-Midwest	Kentucky, Illinois	Illinois
Southeast	Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, Tennessee, Virginia	South Carolina
Northeast	Connecticut, New Jersey	Connecticut
Appalachian	Delaware, Maryland, Pennsylvania, West Virginia	Pennsylvania

* A host state has not yet been designated for the Rocky Mountain compact.

Within the Appalachian Compact, Chem-Nuclear Systems Inc. (CNSI) is the contractor managing the siting and development of the LLW disposal facility. CNSI issued the third interim report on areas thus far disqualified for consideration as LLW sites in May 1994. Approximately 75 percent of the state of Pennsylvania has been disqualified. Identification of three potentially suitable sites is expected, with operation beginning in 1999.

The anticipated costs associated with the siting, licensing and construction of the Appalachian Compact disposal site have increased significantly. CNSI now estimates that it will need an additional $55 to $90 million over the existing $29.2 million contract to complete the project. CNSI states that the extensive public involvement in the siting process, the fact that siting is a regulated activity in Pennsylvania, and experience learned from other siting characterization processes (in Illinois and North Carolina) account for the increased costs.

The NRC is developing guidance on determining compatibility of LLW regulatory programs in the Agreement States (host states for the various compacts) with NRC standards. The agency has determined that Agreement States should be allowed sufficient flexibility to prohibit particular, but not all, disposal technologies, as well as the flexibility to require use of specific disposal technology. Agreement States may establish pre-closure operational release limit objectives or design objectives at such levels as the state may deem necessary, so long as the level of protection of public health and safety is not less than that afforded by NRC rules. No state program has yet been approved that has radiation protection standards *more* stringent than the federal rules. Pennsylvania's LLW regulatory program has been found to be consistent with NRC requirements.

Competition in the Electric Utility Industry

Over the last few years, competition among electric utilities at the bulk power level has increased, spurred significantly through the efforts of FERC. FERC has used its power over mergers and its authority to approve market-based pricing of bulk power to encourage open access to transmission. The Energy Policy Act of 1992 (EPACT) codified FERC's power to order transmission access. In addition, EPACT increased competitive alternatives by amending the Public Utility Holding Company Act of 1935 (PUHCA) to create a new entity, the exempt wholesale generator (EWG). This permits larger firms to own and operate generating stations to compete with utilities' own generating plants.

The actions taken so far to introduce competition have primarily been the federal initiatives governing **wholesale** power transactions. State regulators — including the Maryland PSC — are beginning to explore the deregulation of power supply at the **retail** level. While little has actually occurred so far, retail deregulation has the potential to profoundly alter the operation of Maryland electric utilities.

Transmission Issues

The transmission grid of vertically integrated utilities has been considered by some to be a bottleneck that has thwarted entry to the bulk power market by numerous potential competitors. Transmission, which is essential for many potential transactions, could be difficult to obtain, particularly if the utility controlling transmission capacity has reserved it for other purposes. During the past several years, a number of utilities attempted multi-utility mergers. This provided FERC with an opportunity to condition merger approval upon the applicants agreeing to grant third parties access to their transmission grids ("open access"). The desire of many utilities to sell power on a competitive basis, unfettered by the constraints of cost-of-service regulation, provided added impetus toward transmission open access. In effect, FERC required transmission open access as a *quid pro quo* for granting such freedom. The 1992 EPACT amended the Federal Power Act so that FERC now can order transmission access upon the application by another utility. Additionally, in March 1995, FERC issued its Notice of Proposed Rulemaking on open transmission access. The proposed rule is intended to encourage lower electricity rates by reducing barriers to wholesale transmission access. The proposed rule includes a generic requirement for utilities to provide open, non-discriminatory transmission access.

Transmission Pricing

Utilities have used a variety of pricing mechanisms to establish the terms and conditions under which they provided transmission services to third parties. Many simply computed the average cost of their transmission facilities, divided those costs by their annual peak demand (as a proxy for the capacity of the grid), and charged the resulting dollars per kilowatt transmission rate. This was normally a "postage stamp" rate that reflected neither the distance of specific transactions nor the impact on the grid of actual power flows.

Other transmission pricing schemes used by utilities included the **contract path** and MW-mile method. The contract path method is based upon a presumed electrical path associated with a specific transaction. The MW-mile method reflects the fact that power flows over all parallel paths in an interconnected transmission grid. The MW-mile method compensates all utilities whose facilities are used in a given transaction in proportion to that use.

Additional pricing problems arise when capacity on the grid is constrained. FERC, in approving open access transmission rates during the past few years, has used the so-called "or" policy to set transmission rates. This is designed to protect native load customers from any increased costs of providing transmission to third parties. If such third-party transmission can be provided only through the construction of new facilities, FERC will permit transmission rates to reflect the greater of the average embedded cost or the incremental cost of the new facilities. If transmission can be provided by redispatching existing generation, or by foregoing transactions that increase customers' costs, these "opportunity" costs should be recoverable through transmission rates. Unless this approach is used, native load customers will see their rates rise as a result of providing transmission access.

FERC has issued a Notice of Inquiry to address transmission pricing issues such as these. In its notice, FERC asks whether the "or" policy is sufficient to induce the construction of additional transmission facilities, or whether utilities must be given additional incentives.

In October 1994, FERC issued a policy statement concerning transmission prices. FERC concluded that pricing flexibility was required to accommodate the evolving needs of transmission owners and users in a more competitive era. Under the Commission's policy statement, transmission pricing proposals must adhere to five principles: 1) allow recovery of embedded cost of service; 2) provide comparable service for all users; 3) promote economic efficiency; 4) promote fairness; and 5) be practical. Any transmission pricing proposal failing to adhere to the first two of these would be rejected. FERC expected that it would be difficult to fashion transmission pricing proposals consistent to the same extent with all of the last three principles. FERC would therefore have to judge the extent to which a particular pricing proposal, on balance, was consistent with the principles. The policy statement also concluded that the "or" policy provides sufficient incentives for utilities to provide additional transmission.

Competitive Bidding Programs

As a result of FERC regulatory initiatives and the 1992 EPACT, wholesale bulk power markets have become dominated by competitive forces. This competition has created an opportunity for Maryland utilities seeking new power supplies. Traditionally, utilities have either constructed their own power plant capacity when needed, or purchased capacity through contracts resulting from bilateral negotiations. An example of the latter is PEPCO's 450-MW, 20-year purchase from Ohio Edison Company. Power supply contracts with qualifying facilities would be negotiated using the utility's projections of its avoided costs for guidance on the pricing terms.

Increasingly, utilities have turned to competitive bidding programs as the primary means of acquiring new capacity. A number of states, including Virginia, New Jersey, New York, and the New England states, have sanctioned or required bidding systems as the means of obtaining new capacity. In April 1994, the Pennsylvania Public Utility Commission issued an order requiring utilities in that state to conduct competitive bidding as the exclusive means of adding capacity. In August 1995, the Maryland PSC ordered a similar process.

In Maryland, Delmarva Power conducted two solicitations in the early 1990s for 100 and 200 MW of new capacity. Old Dominion Electric Cooperative (ODEC), the generation company that supplies power to Choptank and other rural cooperatives, conducted a competitive bid to acquire capacity as a partial replacement for its wholesale purchases from Delmarva Power. The winning bidder, Public Service Electric and Gas Company in New Jersey, will supply 150 MW to ODEC under a 10-year contract beginning in 1995.

The only instance in which the Maryland PSC has ordered competitive bidding is for BGE, as an outcome of the Perryman licensing case (Case No. 8241, Phase II; see discussion in Section 2 of this report). BGE completed its solicitation in the spring of 1994 and has entered into a long-term contract for 140 MW with PECO Energy. In that solicitation, BGE received 28 proposals totaling 3,200 MW of capacity. BGE plans to utilize competitive bidding to meet its future supply-side capacity needs.

The use of competitive bidding results in aggressive price competition among both NUGs and other utilities in the region with excess capacity available for sale. Competitive bidding results can also serve as a benchmark or standard for evaluating the cost-effectiveness of the utility's own construction projects.

Exempt Wholesale Generators (EWGs)

Section 711 of the 1992 EPACT establishes EWGs, a class of electric utilities that are exempt from the provisions of PUHCA. PUHCA was adopted in the mid-1930s to deal with abuses in the electric and gas utility business. Under PUHCA, the Securities and Exchange Commission adopted regulations applicable to electric and gas utility holding companies, defined to be any company owning, directly or indirectly, 10% of the stock of a public utility company. Among other things, PUHCA regulations require a holding company to obtain prior approval for issuing securities or for acquiring utility property. These regulations also limited holding company operations to a group of related operating utility properties within a specific geographic region.

Under Section 32 of PUHCA, as amended by Section 711 of EPACT, EWGs are defined to mean any person determined by FERC to be engaged exclusively in the business of owning and/or operating all or part of one or more eligible facilities and selling electric energy at wholesale. An EWG may also sell energy that it has not generated at wholesale, provided that it does not function exclusively as a marketer.

Market-Based Pricing

Bulk power sales among utilities are subject to FERC rate regulation under the Federal Power Act. This means the selling utility's rates are scrutinized to make certain they do not exceed the cost of providing service plus a reasonable profit. Within the last few years, in an effort to inject competition into the bulk power market, FERC has approved various market-based pricing proposals that exempt utilities from cost regulation. A utility seeking approval of a market-based pricing proposal must, however, demonstrate that it has taken steps to mitigate its market power in the bulk power market. Normally, this requires the utility to file an open-access transmission tariff so that potential buyers will be able to choose among alternatives in the market. The only remnant of cost regulation is the requirement that market-based prices be less than the buyer's long-run marginal cost. Since buyers are unlikely to enter into a transaction if the cost exceeds this level, it is unclear if this is much of an impediment.

Retail Competition

Until 1994, the trend toward competitive power markets was largely perceived as taking place primarily in wholesale markets — that is, as transactions between utilities, or between NUGs and utilities. Retail electric service competition exists, but in most areas it is both gradual and limited. For example, gas and electric utilities compete to serve the home heating load; however, once a customer adopts a particular heating system, the gas or electric utility is very unlikely to lose the customer for many years. Thus, active competition is largely confined to new customers or possible customers replacing a heating system. Similarly, electric utilities may compete for large business customers, for example, inducing a customer to remain within the service area. Business relocation due to electric rates differentials is relatively infrequent, however.

Following the path of open access transmission at the wholesale level, a number of analysts and customer groups are urging the same practice at the retail level. This is known as "retail access" or "retail wheeling" and has become a subject of intense debate during the past year. Retail access implies a fundamental restructuring and partial deregulation of electric utilities. At least two states have begun to explore such structural changes. In California, the Public Service Commission issued a sweeping proposal to phase in by 2002 a deregulation of electric generation in that state. In Michigan, the Public Service Commission has approved a limited, five-year retail access experiment, involving about 150 MW of retail load. A number of other states are conducting investigations or inquiries regarding retail competition, deregulation, and new forms of regulation.

In late 1994, the Maryland PSC docketed its own investigation of these issues (Case No. 8678). Unlike California, the Maryland PSC has not issued a specific proposal to restructure the state's utilities or to fundamentally change regulation. Rather, the purpose is to solicit information and ideas from interested parties regarding whether such changes are feasible and desirable. If such changes are deemed to be in the public interest, there are numerous complex issues concerning how it should or could be implemented.

The potential impact of retail restructuring on environmental quality in Maryland is not well understood. Retail access would in no way alter the obligation of utilities to meet existing state and federal environmental regulations; however, environmental quality involves much more than direct regulatory compliance. Competitive restructuring of generation is likely to alter the siting of new generation resources, possibly leading to a greater reliance on non-Maryland sources. The cost minimizing pressures resulting from retail deregulation may undermine the historic willingness of Maryland utilities to cooperate voluntarily in efforts to mitigate environmental impacts from power supply. Competitive pressures are already affecting the willingness of Maryland utilities to invest heavily in customer energy efficiency programs. Retail competition undoubtedly would alter a number of utility practices which today are based on cooperation with the State and meeting long-run social objectives. In its order, the PSC decided that it was premature at this time to address retail access. Rather, it was decided that the PSC should closely monitor retail access in other states and policy development at the federal level.

Competition and the IRP Process

There is little question that the introduction of enhanced retail competition will produce profound changes in utilities' current integrated resource planning (IRP) practices. Today, utilities plan for the future demands of their customers by integrating the most cost-effective supply- and demand-side resources to produce a least-cost resource plan. The preparation of such a plan requires integrating numerous forecasts of peak demand and energy needs, fuel forecasts, and forecasts of capital and operating costs of resource alternatives. The utility's ability to forecast its power demands will be greatly compromised with retail competition. In addition, the greater risk associated with a more competitive environment will shift management's focus to short run considerations and away from longer run planning options.

Consider the case in which the utility's retail customers are granted the right to shop among alternative sources for the lowest-cost supplier of electricity. In such a situation, the utility would have to estimate both total market demand and its own market share, a far more difficult undertaking than is required under the current regulatory structure. How this would affect the selection of supply-side resources is unclear. It is possible, for example, that the increased uncertainty of the load forecast (and cost recovery) would encourage the construction of smaller, less capital intensive generating units.

The ultimate effect of competition on the cost of power is unclear. On the one hand, the disruption of the planning process in a competitive environment may bias utility supply decisions away from large and/or capital intensive supply options, and, as will be discussed below, DSM programs. Perhaps more than offsetting this disruption is that competition greatly encourages cost control in power supply.

DSM and Competition

A fundamental feature of the types of conservation programs provided by Maryland utilities is that they subsidize the purchases of energy efficient measures or equipment for the participating customer. As long as the utility can operate as a protected monopoly, this system of subsidies is a workable mechanism for inducing utility customers to adopt high-efficiency measures. Since Maryland utilities generally have been guided by the Total Resource Cost (TRC) test (see "Rates vs. Bills"), customers in the aggregate can expect an overall savings in their electric bills. However, many of these programs are quite expensive and will result in an increase in electric rates, particularly in the near term. A system of conservation subsidies which results in increased retail rates is viable if the utility operates as a monopoly. Such a system may not be workable, however, in a truly competitive market since customers with competitive choices for power supply will be strongly influenced by rate levels.

The newly emerging competitive threat — even if substantial retail competition does not presently exist — seems to be influencing thinking on DSM. Even though the TRC test has been used in Maryland to screen candidate programs, programs that potentially increase rates are now coming under closer scrutiny. While utility interest in DSM remains strong, utilities are exploring program designs that de-emphasize large scale subsidies (i.e., rebates) as financial inducements. This is particularly true for large commercial and industrial customers, which are perceived as having competitive options.

This change in direction has been announced by Maryland's two largest electric utilities, PEPCO and BGE. PEPCO's Preferred Plan narrows the focus to three major conservation programs — commercial customer rebate, Building Design, and High Efficiency air conditioners. (This is in addition to the company's extensive load management programs.) As a result of the refocus, PEPCO now expects to achieve 70% of the projected energy savings from its previous portfolio of conservation programs but at only 45% of the cost. BGE also is presently considering program redesign approaches that de-emphasize rebates but will provide program participants with technical assistance and financing of on-site efficiency investments.

It seems clear that competitive pressures are currently playing an important role in utility DSM planning and program design. The challenge will be to fashion conservation programs and energy services that foster widespread energy efficiency without high levels of utility spending on rebates and other customer subsidies. The ultimate role of DSM in an increasingly competitive electric utility industry has not yet been resolved.

Environmental Externalities and Resource Planning

The Concepts

Potentially adverse environmental and social impacts of power generation are part of the "social cost" that the citizens of Maryland incur to obtain electric service. Several agencies in Maryland work in concert, as part of the power plant licensing process, to evaluate potential environmental and social impacts from the construction of new power plants in the state. Existing, older plants are subject to a range of environmental regulations such as the federal Clean Air Act and other legislation. These regulations help to manage, limit, and mitigate environmental impacts, but they are not designed to eliminate them.

With growing public concern in recent years over environmental quality, a number of analysts and policy makers have focused on how the electric utility planning process accounts for these social costs. In particular, electric utilities face a range of feasible resource options for meeting the growth in power demands. Since these options have differing implications for environmental quality, are the intrinsic environmental attributes "adequately" accounted for in the utility's planning process? For example, a new coal plant and conservation programs both may be feasible ways of meeting the growth in power demands but have differing environmental implications over a vast range of pollutants and natural resource usages. This is true even though the coal-fired power plant must meet all air and water quality regulations and employ reasonable measures to minimize environmental impacts.

Although Maryland's electric utilities practice integrated resource planning, the methodologies used may not fully capture the environmental attributes of resource options.

DSM Cost-Effectiveness: Rates vs. Bills

Conservation advocates and utility managers generally agree that demand-side management (DSM) programs merit funding by the utility if and to the extent they are cost-effective. The problem is that the two groups cannot always agree — even on a conceptual level — on what the term "cost-effective" means. Various tests of cost-effectiveness have been developed that measure different attributes. The debate centers on whether the purpose of DSM and integrated resource planning is to minimize the total cost that the utility's customers incur for electric service, or whether the goal is to keep electric rates (i.e., average cents per kWh) as low as possible. This is the "rates versus bills" debate.

Conservation advocates generally support measuring DSM cost-effectiveness using the "total resource cost" (TRC) test. This test measures the cost-effectiveness of a DSM program as a comparison of the total utility and customer spending on conservation (excluding rebates or rate discounts) with the total dollar savings in utility expenditures on supply-side resources (e.g., fuel, new generating capacity, etc.) attributable to the expected conservation from the DSM program. If the costs are less than the savings, then utility customers *in the aggregate* come out ahead and the program is deemed to be cost-effective. The program may lead to higher electric rates, but this is unimportant because the higher rates would be more than offset on the average customer's bill by fewer kWhs purchased. According to this view, the customer cares more about his total electric bill than the cents per kWh rates which underlie the bill.

Some utility managers believe that DSM programs that lead to electric rate increases should not be viewed as cost-effective, even if they provide savings in electric bills. They advocate the rate impact measure (RIM) as the proper measure as to whether a DSM program is cost-effective. In addition to including all program costs (including rebate expenses) and utility savings, this test also recognizes as a cost to the utility the loss in revenue caused by conservation. The RIM test can be used to determine whether a program creates distributional impacts among groups of customers. For example, if a program fails the RIM test, participating customers may still benefit (due to their reduced bills) but customers not eligible or able to participate will experience higher rates and therefore higher bills.

The "bills versus rates" debate is likely to intensify due to heightened utility concerns over the competitiveness of electric rates. The choice of RIM versus TRC has important implications for the future levels of utility sponsorship of conservation programs.

There are two types of environmental costs. First, the utility must incur capital and operating expenditures to comply with environmental regulations. These expenditures — for example, investments in emissions control equipment for a new plant — are referred to as **private** or **internal** costs. Second, since environmental compliance mitigates but does not eliminate environmental impacts, a class of social costs called **externalities** are also incurred. By definition, the externalities are incurred by society in general but are not paid for by the utility. The utility's IRP process will fully account for the internal or private environmental costs (i.e., compliance costs), but following traditional least-cost planning methods, it will not account for the externalities. Some analysts believe that a utility planning and decisionmaking process that excludes externalities from consideration will lead to flawed resource choices. The flaw is believed to be a systematic one that could lead to resource decisions biased against environmental quality and natural resource preservation.

In recognition of this problem, a number of state regulatory commissions around the United States require or are considering the incorporation of environmental externalities into resource decisionmaking. According to a survey conducted in 1993, approximately 22 state utility commissions have developed procedures for taking environmental externalities into account for resource planning purposes, and a number of other states are considering such action.

The survey indicates that eight states have approved the **monetization** of environmental externalities for planning purposes. This approach requires that the utility assign specific monetary values (e.g., dollars per ton) for the avoidance of certain major pollutants, usually air emissions. While these monetary values do not directly become part of the cost of electricity, the utility must take the monetized costs of emissions into account in its planning decisions. This procedure is often described as **internalizing** the externality.

Monetizing externalities is a controversial step, and despite its introduction several years ago, it has not become widespread. Nonetheless, a number of states have taken limited measures to give recognition to externalities for decisionmaking purposes, short of requiring monetization. Conceptually, the objective is to select electric power resources on the basis of the lowest total social cost, which might not be the lowest dollar (i.e., private) cost. The recognition of externalities is intended to improve economic efficiency in resource planning and reduce the environmental impacts resulting from electricity supply.

In addition to directly monetizing pollutants, states have considered less formal ways of recognizing or partly recognizing externalities.

- Special treatment for conservation - *Some states have recognized that conservation programs (but not load management) are likely to confer environmental benefits, even if the economic quantification of those benefits remains elusive. These states have included percentage adders to the utility power supply costs (i.e., "avoided costs") used to evaluate conservation program cost effectiveness. For example, Vermont has required the use of a 5% "adder" to utility avoided costs when evaluating conservation.*

- Competitive solicitations for power supplies - *A number of states across the country either mandate or sanction competitive bidding as the most appropriate method of acquiring new power supplies. Competitive solicitations typically award contracts by utilizing a scoring system which takes into account both the price bids* *and a range of non-price factors (e.g., location, reliability, fuel type, etc.). It is not unusual for the solicitation scoring system to include environmental impact criteria, thereby giving some weight to environmental attributes in project selection.*

- Qualitative assessments - *While utility resource selection continues to be made primarily on a "least cost" (i.e., least* private *cost) basis, the state utility commission may incorporate a range of qualitative factors in the final resource planning decision. Such factors could include risk, flexibility of the plan, fuel diversity, and environmental attributes. Thus, in the planning and technology selection, environmental attributes could be included as a qualitative factor and might drive the decision if the competing alternatives are a "close call" on a least-cost basis.*

The Approach Taken in Maryland

The Maryland PSC does not have a formal, established policy regarding the treatment of environmental externalities. Although the issue has been discussed, the PSC has not directed that power plant emissions be monetized and included in planning decisions. However, Maryland has taken a number of actions that begin to incorporate environmental externalities into planning decisions.

Conservation programs for Maryland utilities have been planned and designed through collaborative processes. In evaluating the cost-effectiveness of programs and measures, a percentage adder has been applied to the supply-side avoided costs to reflect factors that are excluded from conventional private cost calculations. The environmental benefit derived from conservation is part of the rationale for the percentage adder. In recent years, Delmarva Power and BGE have held capacity solicitations, in each case for about 140 to 150 MW. Environmental criteria were employed, along with price bids and other qualitative factors, as part of project selection.

Delmarva Power's two most recent IRPs have included extensive information on the air emissions characteristics of three major air pollutants (SO_2, NO_x, and CO_2) for the various generation options under review. In evaluating alternative resource plans, Delmarva Power models the total system year-by-year emissions for each of the three pollutants. The information on quantity of pollutants is available to be evaluated, along with conventional measures of cost-effectiveness. Since Delmarva Power's projections of environmental impacts are not monetized (i.e., they are expressed as tons of pollutants, not dollars), the manner in which this information should be used for planning purposes has yet to be resolved.

PPRP has been sponsoring research concerning **social costing** of electricity. Social costing refers to regulatory practices that would require the utility to incorporate externalities, such as environmental impacts, into electric utility least-cost decisions in some manner. These decisions could include both long-run planning and short-run operational (e.g., plant dispatch) decisions.

The study involved a 20-year system planning simulation of a hypothetical Maryland utility, relying heavily on planning data provided by a regional utility. The utility's least-cost planning and system operations were examined after monetizing four major air pollutants and introducing several alternate social costing regulatory regimes.

The study concluded that certain social cost pricing regimes have the potential to significantly reduce the average social cost of providing electric service while also reducing pollution. However, the benefits from social costing vary considerably depending upon the design of the regulatory regime. The most serious conceptual problem arises when only new generating units are subject to social costing regulation but older, existing units are exempt. This leads to a problem known as **anti-new source bias** and potentially can result in even higher levels of pollution and higher social costs of electricity than if no social costing regulation occurred. Thus, if incorrectly applied, social costing regulation can undermine the goals of environmental quality and consumer welfare. The most favorable results are obtained when social costing regulation is comprehensive, applied in a consistent manner to new and existing generating units to eliminate the "anti-new source" bias.

Difficulties in Employing Environmental Externalities

Despite the strong and growing interest in environmental externalities, there are a number of problems that limit its applicability, or at least suggest considerable caution. The most direct method for internalizing the externalities is by requiring monetization of pollutants. This allows pollution to be treated as any other private cost for decisionmaking purposes. The practical drawback is the lack of reliable information concerning the monetary value of reduced pollution. Economists generally agree that monetization values should be based upon damage estimates, and such estimates may differ dramatically from state to state (or even within a state). Very little information on pollution damages is available for Maryland. Even the states that monetize externalities typically use compliance costs as a proxy for damage costs. Further research on Maryland-specific damages from pollution would be needed in order to reliably apply monetization.

Moreover, monetization has been used largely on a narrow set of pollutants, mostly certain air emissions. Electric power production also has important implications for land use, water quality and availability, and waste disposal. In fact, there could be trade-offs among different types of environmental impacts, which monetization may fail to address.

Aside from quantification difficulties, some analysts have criticized social costing solutions to the externality problems as piecemeal. A piecemeal solution, it is argued, could lead unintentionally to reduced environmental quality and unnecessarily higher electric rates. The problem arises because social costing will be applied to the electric utility but not to alternative energy forms, which often are not regulated by the PSC. For example, higher rates due to social costing could induce an industrial customer to seek self-generation. Depending on the fuel type, this could increase pollution.

An analogous problem arises if Maryland employs social costing but states surrounding Maryland do not. In that case, social costing schemes may only succeed in relocating electricity production to other states without serving to reduce pollution (on a regional basis) or improve consumer welfare. Alternatively, Maryland regulators could apply social costing to power imports, but this would greatly complicate the task.

The foregoing discussion is an indication of some of the limitations and complexities of social costing and why caution is warranted. Given the strong public interest in environmental/economic trade-offs, developing practical, constructive approaches to the comprehensive evaluation of the impacts of power generation will continue to be a research priority.