tude of suppliers of electric power generation to choose from, similar to the structure which has in recent years emerged on the wholesale level and in the natural gas industry. Such a scheme would subject electric utilities to a much greater degree of direct competition for the sale of electric generation to their retail customers.

Given the somewhat limited, but growing, retail competition already being faced by the natural gas and electric utilities industry, and the prospect of heightened competition and perhaps retail wheeling on the horizon as business and economic development pressures mount, the financial rating agencies have already begun re-evaluating the degree of business and regulatory risk to which utilities are exposed. This re-evaluation has resulted in lower financial ratings for many gas and electric utilities. Some of the key factors which can negatively impact the perceived future financial performance of an electric utility are high-cost production, a large proportion of industrial loads that are targeted by competitors, high-cost excess capacity, uneconomic plant investment and high-cost power purchase contracts. The specific cause for the potential devaluation of many utilities in the face of heightened competition is the difference between the actual generation costs of a particular utility and the market price for power. Unfortunately, due to a number of economic and environmental factors, New Jersey's electric utilities generally do not fare well in such a comparison due to relatively high production costs. This should be cause for some concern and careful thought as the State considers how to best address the emerging competition issues. Moreover, it is expected that nearby states which currently enjoy lower energy costs, in part due to less stringent environmental emissions standards, will also be implementing policies to assist their utilities and businesses to compete with New Jersey's.

It is expected that over time, the unleashing of the competitive forces in the wholesale power market, as furthered by the proposed IRP/Supply-Side model, will gradually bring down the average electric production costs experienced by the State's utilities. This, in turn, should assist the utilities to control their retail prices and otherwise become more competitive in the retail marketplace.

However, these changes and benefits are not expected to occur overnight. The immediate question is what the State and its utilities can do in the short term to permit the State's utilities the flexibility to compete for their at-risk customers and otherwise offer pricing incentives to promote economic development, while at the same time providing utilities with incentives to control and reduce their costs and rates in order to become more competitive.

Rate Flexibility

Over the past two years, as a result of individual competitive threats or in response to economic development concerns, the Board of Public Utilities has approved a number of tariffs or service agreements which have effectuated or created the opportunity for price discounts for individual customers. Such actions include the New Jersey Steel service agreement, the Bayway refinery contract, and the economic development tariffs for the State's electric and gas utilities. Even more recently, in January 1995, the BPU approved JCP&L's request for rate flexibility in order to implement discounts for its high-volume, residential electric heating customers. Such initiatives have been adopted by the Board of Public Utilities on a case-by-case basis, after extensive and time-consuming regulatory reviews.

While these actions have been taken under current law as embodied in Title 48, several concerns have arisen which question the ability of the utilities and the regulatory process to react in a timely fashion to competitive threats and emerging economic development opportunities. Specifically, while the Board of Public Utilities has asserted its ability to approve such tariffs or service agreements under current law, the continued prospect of legal challenges to that ability casts a cloud over such transactions. Specific enabling legislation will dispel any uncertainty and facilitate the execution of such transactions, ultimately benefiting the State's economic development, as well as the utilities and their customers.

It is therefore appropriate that the Board of Public Utilities develop and propose such enabling legislation to specifically permit the Board of Public Utilities to approve the implementation of rate flexibility by electric and gas utilities. Such legislation will include or provide for the establishment by the Board of Public Utilities of standards to govern such rate flexibility programs. In this manner, all parties will know in advance the conditions for the offering of price discounts and, subject to meeting the prescribed standards, utilities will be able to swiftly negotiate and effectuate such transactions without awaiting the results of a lengthy and complex regulatory review.

A critical issue with respect to the adoption of rate flexibility standards is a policy with respect to the treatment of so-called "lost revenues" resulting from the implementation of price discounts. Lost revenues are generally defined as the difference between the revenues collected from a customer under the discounted price and that which would have been collected at the tariffed, full cost-of-service price. The Board of Public Utilities has generally adopted an approach that lost revenues should not be recovered from other ratepayers, at least until the conclusion of the utility's next base rate case, and should not be subject to deferred accounting. Such an approach is founded on sound ratemaking principles and should be the policy of the State and be embodied in the enabling legislation.

The next issue concerns prospective treatment of such lost revenues at the conclusion of base rate cases. This issue has purposely not been addressed by the Board of Public Utilities during past proceedings, pending the development of a comprehensive rate flexibility and energy policy. Within the context of this document, and resultant implementation steps, such policy can now be developed.

The State should, via enabling legislation, establish standards to govern rate flexibility programs. The standards should include two tiers. The first tier would include the minimum standards that must be met by a utility to implement a discount, whether or not it proposes the recovery of lost revenues from other customers. A second tier of standards would need to be established for application should a utility request to recover a portion of the lost revenues from other customers.

To that end, the Board of Public Utilities should consider including the following standards in its draft Rate Flexibility legislation which must be met by a utility whether or not it proposes the recovery of lost revenues from other customers:

1. a prohibition against any recovery by the utility of the revenue erosion which results from the discount prior to the conclusion of the utility's next base rate case;
2. a requirement that the negotiated rate discount must equal or exceed a minimum, prespecified floor price;
3. a requirement that the duration of the negotiated rate discount agreement not exceed a maximum, prespecified contract term; and
4. a requirement that the customer granted the rate discount have a comprehensive energy audit performed at its site. The energy audit would be considered confidential and if performed at the expense of the utility, should be considered a reasonable utility DSM expenditure for ratemaking purposes.

The Board of Public Utilities should develop the specific implementing details of the standards such as the components of the floor price and the maximum contract term, as well as the reporting requirements which should include at a minimum, the number of rate discounts granted, the dollar amount of the discounts and the aggregate dollar amount of all rate discounts granted. The Board of Public Utilities, in its review of the information filed, should evaluate the aggregate impact of all individual rate discount agreements on the financial integrity of the utility and its ratepayers.

As indicated previously, utilities should be provided an opportunity to recover a portion of revenues lost as the result of rate discounts on a prospective basis at the conclusion of base rate cases. The Board of Public Utilities should consider that such recovery only be permitted if a utility can demonstrate in its base rate case, at a minimum, that:

1. the customer had a viable competitive alternative and the price discount was necessary to prevent a customer from leaving the utility system or relocating operations, or that the price discount induced the customer to relocate to or expand its business in the State;
2. all appropriate offsetting financial adjustments are credited to the revenue requirement associated with that particular base rate case;
3. other ratepayers benefit by the discount having been implemented as compared to had the discount not been implemented, and that cross-subsidization via an inappropriate shift in cost responsibility between customers does not otherwise occur; and
4. the utility has implemented a corporate strategy to reduce its overall level of costs. Importantly, the enabling legislation should provide utilities with the flexibility to act quickly and at their discretion in the offering of individual rate discounts. Provided that the tier-one implementation standards are met, no specific regulatory approvals would be required. However, in implementing a rate discount, utilities will bear the risk for meeting the second tier of standards necessary to receive future rate recovery of lost revenues.

It is important to emphasize that, even if it meets the established rate recovery standards, a utility should only be entitled to recover a portion of the lost revenues. In this manner, a strong incentive will be created for the utility to reduce its costs as a primary long-term means of addressing competitive threats, consistent with the overall energy policy goals of the State as described throughout this document.

It is worth noting that there are significant differences in the current evolution of market structure between the electric and natural gas industries. Moreover, the nature of retail pricing in the two industries, including the parity pricing and margin sharing concepts for gas utilities, is different in many respects. As such, in drafting specific proposed legislation, the Board of Public Utilities will consider whether there is a similar need for specific revisions of law in both the gas and electric industries and, whether different rate flexibility standards for the gas utilities than those enunciated above are appropriate.

Alternative Regulation

There has been substantial recent debate both within the State and nationwide concerning whether the traditional rate-base/rate-of-return mode of regulation continues to best serve the public interest in the face of the fundamental changes sweeping the electric and gas industries. At their core, the current Title 48[16] regulatory standards, the origin of which can be traced back some eighty years, presume the monopoly provision of electric and gas services and base the potential for earnings growth by the utility on the expansion of the rate base, that is, on new plant investments.

As previously discussed, competition in the gas industry now exists virtually from the wellhead to the burner tip. In the electric industry, the generation end of the business is now subject to substantial competition, and some end users are beginning to be presented with choices in terms of source of supply. With market forces increasingly prevalent in many industry segments, it is questionable whether the application of traditional, cost-based regulation standards provides sufficient flexibility and imparts effective incentives to improve productivity and efficiency, reduce costs and encourage appropriate investments.

A number of alternative regulatory schemes, including price caps, revenue sharing, performance-based rates and pricing flexibility, are possible means of more appropriately aligning regulatory practices with the changing nature of the electric and gas industries. In fact, some of these measures, particularly performance-based rate regulation, have already been implemented in a number of states. Indeed, the New Jersey Board of Public Utilities has instituted a number of limited incentive mechanisms, including nuclear performance standards and DSM incentive regulations.

Given the rapidly changing landscape in the gas and electric industries, it is appropriate to provide sufficient flexibility in the regulatory system to allow the Board of Public Utilities to entertain and, if deemed in the public interest, approve alternative forms of regulation. Indeed, the proposed competitive supply-side procurement model might necessitate a ratemaking mechanism other than traditional rate-base/rate-of-return to provide for a meaningful comparison of competing projects.

As such, the Board of Public Utilities will develop and propose alternative regulation legislation which will allow gas and electric utilities to petition the Board of Public Utilities to consider plans for alternative forms of regulation.

It must be emphasized, however, that many segments of the utilities' customer base remain essentially captive to their local utility under the current industry structure. These customers remain reliant on the strong regulatory oversight envisioned in the current Title 48 statute to ensure that they receive safe and reliable utility service at fair and reasonable prices.

It is for this reason that any immediate alternative regulation legislation must be fashioned as a supplement to, rather than a replacement for, the current statutes. It is essential that the legislation create incentives and opportunities for utilities to reduce costs, maintain and improve service quality, promote economic development, be rewarded for accepting higher risks and foster cost-effective energy efficiency and environmental compliance, while at the same time continue the fundamental protection of the captive customer embodied in Title 48.

In order to accomplish this important balance, and in recognition that no specific proposals for alternative regulation have yet been presented for evaluation, it is imperative that the alternative regulation legislation contain specific standards for acceptability of proposed plans. Specifically, the Board of Public Utilities should consider including the following standards in its proposed legislation for approval of a plan for alternative regulation:

1. the plan will produce tangible benefits for the customers of the utility relative to the existing form of regulation;

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2. the plan will create incentives for the utility to control its costs and improve its efficiency and productivity for the benefit of all of the utility's customers;
3. the plan will not diminish service quality standards for customers not agreeing to accept lower quality service;
4. the plan will not result in cross-subsidization either among utility customers or among different segments of the utility's business;
5. the plan will include mechanisms which assure that customers who remain captive to the local utility will continue to have regulatory protection and will pay fair and reasonable rates which are reflective of the cost of service; and
6. the plan will promote the energy efficiency, environmental compliance and economic development goals of the State in a cost-effective manner.

Energy Tax Policies

New Jersey's energy tax policies have evolved over a number of years. While these energy taxes served legitimate public policy objectives when enacted, the existing energy tax structure might not be congruous with the emerging competitive energy markets.

Economic efficiency requires that production cost should be the prime determinant of competitive position. If taxes distort that position, economic efficiency is sacrificed. This could increase energy costs to consumers and is unfair to the affected energy suppliers. Given the trend towards increased competition in the State's energy markets, fair competition requires a re-examination of the State's energy tax policies.

Current tax policies differentiate between competing suppliers of a fuel and between competing fuels. This disparate tax treatment does not result from any single tax but from a combination of various energy, business, sales and property taxes. Any assessment of energy tax policies must assess the combined impact of all taxes.

The key tax policies which impact competition in the State's energy markets, and therefore require review, are as follows:

- The gross receipts and franchise tax assessment that must be collected from public electric and gas utilities on all retail sales. The tax is assessed on a per unit basis and is currently equal to approximately 13 percent of utility revenues. The gross receipts tax was enacted in lieu of State, county, school and local taxes on personal property, while the franchise tax was imposed on utilities for the privilege of exercising their municipally granted franchise and for using public streets and highways.
- The gross receipts and franchise tax hinders fair competition in a number of markets. In the natural gas industry, with the advent of unbundling, natural gas consumers can purchase transportation service from the local utility and the gas from an out-of-state supplier. The transportation service, which represents a small portion of the total cost of delivered gas, is subject to the gross receipts and franchise tax. The natural gas however, if purchased from an out-of-state supplier, would not be subject to the gross receipts and franchise tax.
- By Order dated December 20, 1993, in BPU Docket Number GX93110516, the Board of Public Utilities adopted "Guidelines for the Further Unbundling of New Jersey's Natural Gas Services." The Board's Order expanded the option to purchase natural gas from entities other than the local utility to all commercial and industrial customers in the State. This has the potential to substantially increase the number of customers purchasing gas from out of State and, therefore, avoiding paying the gross receipts and franchise tax.
- The gross receipts and franchise tax gives competitors of the local utility a price advantage equal to approximately 13 percent of the cost of the gas. The State stands to lose significant revenues should a large number of customers exercise their newly acquired option to purchase natural gas from other than the local public utility.
- Natural gas competes with propane and oil as a heating fuel and has recently begun to enter into the vehicular motor fuel market where it is competing primarily with gasoline and propane. The existing tax structure, primarily the gross receipts and franchise tax, places natural gas at a competitive price disadvantage with these fuels.
- In the electric power industry, market distortions are caused primarily by the gross receipts and franchise tax and the general corporation business tax. The gross receipts and franchise tax generally causes distortions in the electric retail markets while the general corporation business tax causes distortions in the wholesale power markets.
- Public utilities are assessed and must collect gross receipt and franchise taxes on all retail electric sales. Nonutility generators, consisting primarily of self-generators and third-party cogenerators, are not assessed nor are they

required to collect gross receipts and franchise taxes on retail sales. However, nonutility retail sales are currently limited to sales to the host customer known as inside-the-fence deals.

- Nonutility facilities are assessed the general corporate business tax equal to 9 percent of New Jersey net income. Utilities are exempt from the general corporate business tax. This tax somewhat offsets the gross receipt and franchise tax advantage realized by nonutility generators on retail sales. This tax might act as a disadvantage to nonutility generators in any direct wholesale competition with a utility, because utilities do not pay this tax.

A critical need exists to examine the competitive consequences of the State's energy tax policies, including the gross receipts and franchise tax, the general corporate business tax, sales and use taxes and property taxes. The existing tax structure favors certain suppliers and certain fuels as an unintended consequence of tax policies which were enacted for purposes other than favoring certain suppliers or fuels. On that basis, the Board of Public Utilities and the Department of Treasury should jointly develop a process for developing specific tax policy recommendations.

The State annually collects approximately $1.1 billion from utilities in gross receipts and franchise taxes, including approximately $1.0 billion from the State's gas and electric utilities. By statute, a minimum of $685 million is allocated to the State's municipalities. Any consideration of modification to tax policies must therefore consider the significant potential impact on municipalities. Specific tax policy recommendations must also consider the fiscal constraints faced by the State.

Findings:

- Existing energy tax policies hinder fair competition between competing fuels.
- Existing energy tax policies hinder fair competition between competing suppliers of the same fuel. This is particularly true for competition between utility and nonutility firms.
- Increased competition in the natural gas and electric industries has the potential to significantly reduce the State's collection of gross receipts and franchise taxes.

Recommendations:

- ▲ Energy tax policies must take into consideration regional competitiveness. New Jersey's energy taxes should not place the State's industries at a competitive disadvantage with industries in other states in the region.
- ▲ The Board of Public Utilities and the Department of Treasury should jointly develop energy tax policy recommendations. The energy tax policy recommendations should consider the appropriateness of a fuel neutral tax policy, tax policies which promote the State's environmental and energy efficiency objectives and tax policies which do not differentiate between suppliers of the same fuel in both retail and wholesale markets.
- ▲ The Board of Public Utilities and the Department of Treasury should jointly initiate the development of energy, end use and tax revenue economic models to assess the impacts of various alternative tax scenarios.
- ▲ The State should consider the stability of the existing tax base and the subsequent tax revenues collected during the transition from regulated to more competitive markets.

Demand-Side Management

The move towards competition in the State's energy markets does not diminish the fact that demand-side management (DSM) or energy conservation has the potential to benefit the State in many ways. DSM benefits the State by reducing the need to import fuel, thereby keeping energy dollars in-state. DSM benefits the environment by reducing the amount of fuel burned to meet our energy needs. DSM can defer or eliminate the need to site and construct new generating facilities. Finally, DSM can enhance economic development by reducing the energy bills of the State's businesses and residents.

On the negative side, DSM, even when it is the lowest cost option to meet energy needs, can increase prices. This is caused by the fact that DSM reduces sales, thereby spreading costs over a smaller sales base and increasing the per unit cost. The end result is that while DSM can benefit the State by reducing overall energy costs, and can benefit the household or business which installs a DSM measure by reducing it's energy bill, DSM can raise the rates and bills of customers that do not install DSM measures. This raises issues of equity between customers that participate in DSM programs and those that do not.

The Board of Public Utilities adopted DSM incentive regulations which became effective in November 1991. The DSM incentive regulations provide the State's gas and electric utilities with an incentive to invest in DSM. Prior to the adoption of these rules, utilities recovered prudent DSM expenditures with no opportunity for profit. The DSM incentive regulations provide utilities an opportunity to both recover costs and earn a profit on successful DSM programs.

The DSM incentive regulations also eliminated a disincentive to DSM which occurs because DSM reduces a utility's sales. The DSM incentive regulations provide an opportunity for utilities to recover the contribution to fixed costs it would have collected had the energy been sold instead of saved.

Initial indications are that the DSM incentive regulations have been successful in heightening the State's gas and electric utilities' interest in implementing DSM programs. The State's utilities' combined budgets for DSM has more than doubled from approximately $40 million per year in 1991 to over $100 million in 1993.

The Board's DSM incentive regulations incorporated two notable provisions. First, the utilities' incentives are based on energy savings which are measured and verified pursuant to a Board of Public Utilities approved protocol. By basing incentives on savings rather than on expenditures or the number of measures installed as many other states do, the regulations send a strong signal to concentrate efforts on the most cost-effective DSM measures. Requiring strong measurement and verification ensures that the savings are real.

The second notable feature is the flexibility provided to utilities in designing DSM programs. This provision has resulted in utilities experimenting in various ways to deliver DSM programs to different markets.

The DSM programs implemented subsequent to the adoption of the incentive regulations are, for the most part, in their infancy. Sufficient time has not yet passed to assess the various programs.

Given that sufficient time has not passed to assess the DSM incentive regulations or the programs implemented pursuant to the regulations, the best course of action at this time is to continue the experiment. Changing policies at this time could disrupt a marketplace which is just beginning to understand the new rules.

While it is best to stay the course on DSM at this time in terms of the overall process, several issues have arisen which require additional investigation. Specifically, issues have been raised concerning the appropriateness of fuel switching as a DSM measure, the eligibility of electric reductions as a by-product of a cogeneration facility, the role of the Total Resource Cost (TRC) test and the constraints imposed by the public bidding laws. Phase II of the Energy Master Plan should include workshops to discuss these and other issues related to DSM.

Findings:

- The DSM incentive regulations have resulted in significant increases in utility DSM budgets.
- Sufficient time has not passed to assess the DSM incentive regulations or the programs implemented thereto.
- DSM can continue to provide benefits in a competitive marketplace.

Recommendations:

- The Board of Public Utilities should not make any major modifications to the DSM incentive regulations at this time.
- The Board of Public Utilities should assess the DSM regulations and the utility programs implemented pursuant to those regulations after sufficient time has passed to properly assess the programs.
- The Board of Public Utilities should coordinate public workshops in Phase II of the Energy Master Plan to identify specific issues related to the implementation of the DSM regulations and to discuss proposed solutions.

Energy Policy and Air Quality Planning

Protection of the environment and concern for public health and safety are important objectives in setting energy policy. Energy issues are discussed and decided within an integrated energy and environmental resource planning framework that includes impacts on air quality and water supply, airshed emission transport, plant and animal ecosystems, land use and transportation systems. Energy policy-making considers water standards, coastal protection and wetlands requirements, Federal greenhouse gas initiatives, and toxic emissions such as mercury.

Energy generation and use, however, often has the most significant impact on ambient air quality. It is estimated that 1,800 tons of volatile organic compounds (VOCs), 1,500 tons of oxides of nitrogen (NOx), and 4,450 tons of carbon monoxide (CO) are emitted into the air over the State each day, primarily from the combustion of fossil fuels to meet our energy needs[17]. The pollutants are emitted by the many industrial sources that use, transfer or dispose of fossil fuels and solvents; the power plants that generate our energy; the fuels that we burn to power our cars, buses, trucks, and other vehicles; and the construction, farming and garden equipment that we operate.

Efforts to achieve energy efficiency, such as those strategies included in demand-side management programs, can significantly reduce the amount of energy used and pollutants emitted into our environment. Renewable energy technologies can also contribute to a reduction of VOCs, NOx and other pollutants.

The VOC and NOx emissions are primary or precursor pollutants that react in the presence of strong sunlight to produce ground-level ozone, the principal component of smog. Ozone can form hours after the precursor pollutants are emitted and miles from the pollutant sources.

Exposure to ozone and other pollutants negatively affects the public health as well as the economy. Individuals exposed to ozone have an increased probability of experiencing respiratory problems, and high levels of ozone affect the economy by damaging crops and forests, decreasing crop yields, eroding synthetic materials and degrading the quality of life that is necessary for a vibrant economy.

The reduction of pollutant emissions is governed by the overlapping requirements and guidance provided by the Federal Clean Air Act Amendments of 1990 (CAAA) and the Energy Policy Act of 1992 (EPAct). When compared to the National Ambient Air Quality Standards (NAAQS) set by the CAAA, air monitoring results show that ozone levels remain at unhealthful levels throughout the entire State. Significant areas of New Jersey also do not meet the Federal health standard for carbon monoxide.

The CAAA established a three-part process for meeting the emission reduction targets for ozone. In step one, submitted in November 1992, New Jersey committed to implementing basic controls mandated by the CAAA. Step two, submitted in November 1993, demonstrated that New Jersey will achieve by 1996 a 15 percent reduction in VOC emissions from a 1990 baseline. Step three requires a full demonstration of attainment with the NAAQS by the year 2007, at the latest.

New Jersey has developed a comprehensive emissions reduction strategy, encompassing both mobile and stationary sources, to be implemented over the next few years, that includes:

- a revision to the emission offset rule which ensures that new construction and alteration of major sources of air pollutants do not result in significant increases in emissions of VOC and NOx;
- Reasonably Available Control Technology requirements for major sources of VOCs (VOC RACT), including wastewater treatment facilities and offset printing operations;
- Reasonably Available Control Technology requirements for major sources of NOx (NOx RACT);
- an Enhanced Inspection and Maintenance Program (Enhanced I/M) for motor vehicles;
- an Employer Trip Reduction Program aimed at reducing by at least 25 percent the commuters who drive alone to work;
- various transportation control measures (TCMs) to offset increases in emissions due to growth in vehicle miles traveled;
- reformulated gasoline in motor vehicles and equipment;
- controls on emissions resulting from the transfer of gasoline to barges;
- State measures to reduce emissions from architectural and industrial maintenance coatings;
- a low emission vehicle program; and
- standards for VOC content in consumer products.

Although the regulatory measures committed to in the

SIP encompass both mobile and stationary sources, it will be difficult for New Jersey to meet the NAAQS for ozone by the deadlines specified in the CAAA. New Jersey will also need to reduce NOx emissions beyond what is required in the Reasonably Available Control Technology (RACT) rule, in addition to its VOC reduction strategies.

To meet the deadline for the attainment of the ozone NAAQS, the twelve member states of the Ozone Transport Region (OTR), which reaches from Virginia to Maine and includes the District of Columbia, have worked together to develop a regional control strategy that could reduce stationary source NOx emissions by as much as 70 percent in the aggregate by the year 2003, from a 1990 baseline[18]. The strategy would require further reductions in NOx emissions than are currently required from large fossil fuel-fired boilers and other indirect heat exchangers with a maximum gross heat input rate of at least 250 million British thermal units (Btus) per hour.

The regional control plan reflects the differences within the twelve states and the District of Colombia by establishing three zones with separate NOx reduction targets: the Inner Zone, which includes all of New Jersey except Warren County, the Northern Zone, and the Outer Zone which includes Warren County. The emissions reduction would occur in a two-step process by the years 1999 and 2003.

By May 1, 1999, the affected sources in the Inner Zone will reduce their rate of NOx emissions by at least 65 percent, or emit NOx at a rate no greater than 0.2 pounds per million Btu. The sources in the Outer Zone will reduce their NOx emissions by at least 55 percent, or emit NOx at a rate no greater than 0.2 pounds per million Btu. These options are expected to result in reductions of approximately 60 percent in the Inner Zone, and 50 percent in the Outer Zone by 1999.

Although the two zones differ in the required percentage of total NOx emission reduction required for 1999, the alternative allowable rate of emission is uniform. In addition, this 10 percent difference between the 65 percent and 55 percent reduction requirements represents a limited and temporary differential between the two zones. By the year 2003, both the reduction of total emissions (75 percent) and the 0.15 pounds per million Btu alternative rate will be uniform for the Inner and Outer Zones. Note that the Northern Zone contains no major power generating facilities.

This agreement represents a consensus-building process over a two-year period which included numerous public meetings. The differing NOx standards set for the zones during the interim four-year period, however, will necessitate that the environmental costs of energy generation be assessed as a separate component in the integrated resource planning process.

The NOx control strategy includes a region-wide emissions allowance trading system to permit affected sources to meet annual reduction targets in a more cost-effective manner. To test the feasibility of this regional market-based NOx reduction mechanism, the Northeast States for Coordinated Air Use Management (NESCAUM) and the Mid-Atlantic Regional Air Management Association (MARAMA), collaboratively developed a conceptual emissions budget and trading system for electric generating units and large industrial boilers, the principal stationary sources that emit NOx in the Ozone Transport region. ("Feasibility of a Regional Market-Based NOx Budget System for the Ozone Transport Region," September 1994)

The study was guided by several primary objectives:

1. to promote innovative and cost-effective approaches to NOx emissions reduction by stationary sources;
2. to allow flexibility in meeting reduction targets through options such as energy conservation and seasonal fuel switching;
3. to increase certainty in NOx emission reductions and thereby assist in meeting ozone attainment deadlines by developing long-term reduction targets in advance;
4. to encourage stationary sources to make reductions sooner, thereby reaping benefits of improving air quality; and
5. to satisfy the United States Environmental Protection Agency's (EPA) rule for discretionary Economic Incentive Programs (EIP), which is the most flexible mechanism available for implementing an interstate control program.

The NOx control strategy, in order to limit the tons of NOx released into the atmosphere, would grant allowances (authorizations) for NOx emissions to the affected sources, primarily utility generating facilities, based on the Ozone Transport Commission Memorandum of Understanding (September 27, 1994) and the emissions budgets developed for the three zones. An affected source that overcontrols its NOx emissions to below specified compliance limits could trade its surplus allowances to a source that undercontrols.

Under an allowance trading system, trades of allowances may proceed without prior State approval, provided defined criteria are met. The affected sources would annually submit reports to the State, documenting that their NOx emissions during the ozone season, between May through September, did not exceed the source's allowances.

Emissions allowances could be traded, bought, or sold for use by any other source located within the same budget zone. Trading between budget zones would be subject to exchange rates. Banking of unused NOx allowances by affected sources for use in future years is a possible element of an emissions trading system, and might be allowed with restrictions to protect air quality.

Federal and State studies confirm that current retrofit technology can achieve NOx emission rates at or below 0.10 pound/million British thermal units (MMBtu), in most cases. Selective Catalytic Reduction (SCR), in combination with combustion controls, has been demonstrated to lower NOx emissions for coal-fired boilers to less than 0.05 pounds per MMBtu, for oil and gas-fired boilers to less than 0.02 pounds MMBtu, and for gas turbines to less than 0.03 pounds per MMBtu.

The analysis demonstrated that a NOx budget based on an average emission rate across the OTR of 0.15 pounds MMBtu, would produce summer NOx reductions of about 70 percent relative to a 1990 baseline. The study has further established that a balanced emission reduction strategy, in which existing regulatory measures are buttressed by economic incentives, is a more cost-effective approach to achieve the additional NOx reductions, rather than reliance solely on performance limits for each affected combustion unit.

A recent study conducted by ICF Resources Inc. for the coal industry, entitled "Estimated Costs in the PJM and NY Power Pools of Alternative NOx Controls on Electric Utility Sources" (August 1994), estimated that the overall costs of NOx reductions can be reduced in the PJM Power Pool by at least 37 percent (with a 0.15 pounds per million Btu limit case) and up to 53 percent (with a 0.30 pounds per million Btu limit) by incorporating a trading system into the command and control compliance strategy to achieve emissions reduction targets. This type of market-based approach could encourage environmental improvement beyond required action.

A regional emissions trading program can have long-term, as well as shorter-range implications, for energy policy. In the long term, a regional strategy is needed to assist in energy market-restructuring, as well as for addressing environmental issues. Economic incentive strategies, developed and implemented by a regional entity, can offer substantial opportunities for environmental and economic improvement.

In the short term, a regional emissions control and trading program can simplify integrated resource planning and encourage the implementation of demand-side management (DSM) strategies. A trading system could further support DSM by allowing credit for emissions reduction achieved by energy conservation measures.

Findings:

- The policies that govern energy generation have a significant impact on environmental quality and public health.
- The development of energy policy should include an environmental analysis that considers impacts on air and water standards, coastal protection policy, Federal initiatives on greenhouse gases and toxic emissions.
- A significant amount of air pollution is transported into New Jersey from sources, such as power plants, that are located in other states; consequently, a region-wide emission reduction strategy is necessary to enable the State to meet the Federal health standards.
- New Jersey energy policy should be consistent with the requirements of the Federal Clean Air Act Amendments of 1990, as well as the National Energy Policy Act of 1992.
- Energy policy should reflect the strategies in the State Implementation Plan (SIP) for air quality improvement, and should work towards meeting the NAAQS for ozone by reducing emissions of VOCs and NOx.
- Energy and environmental planning should rely on a comprehensive and coordinated approach that encourages the development of market-based forces to achieve

environmental goals at the lowest reasonable cost.

- Energy efficiency and DSM strategies can reduce the amount of pollutants released into our air while simultaneously lowering customer energy bills, stimulating the development of energy-efficient equipment, reducing utility operating and maintenance costs, and providing improved safety and health conditions.
- Energy efficiency and conservation measures should be included in rate flexibility guidelines, and used as a tool for maintaining large industrial energy customers in the State's existing rate base by reducing their energy bills.
- Integrated resource planning (IRP) is a valuable tool to identify cost-effective DSM strategies and least-cost supply-side resources. Energy efficiency resources should be assessed in an IRP process where environmental costs and benefits are included in the assessment methodology until the development of market-based incentives to attain environmental goals.
- Promoting renewable technologies can provide increased energy security by reducing New Jersey's vulnerability to price volatility and supply, as well as protect the environment.
- In determining the relative costs of various resource options, integrated resource plans should consider long and short-term benefits of renewable energy and energy efficient technologies such as cogeneration.
- An emissions trading system could provide a market-based economic incentive for the development and implementation of DSM, as well as provide a mechanism for integrating environmental externalities in energy decision making.
- A NOx emissions budget system, established to limit NOx emissions, could include allowance trading. An allowance trading system provides a flexible mechanism for attaining emission reduction goals and offers advantages to energy generators. Under an allowance system, affected facilities would document that their emissions totals are within their facility budgets. Emission reductions from DSM, fuel switching, add-on controls or any other alternative measure could be used to ensure that the budget limit is met.
- The NOx emissions budget system, like the Federally mandated acid rain program, addresses only a single air contaminant (ozone and sulfur dioxide, respectively). A comprehensive emissions control program that considers the need for reductions of mercury, particulates, and other pollutants and toxics as well, could be considered in contrast to a pollutant-by-pollutant regional control strategy.
- A comprehensive emissions reduction strategy that includes NOx, sulfur dioxides, mercury, and particulates would increase the value of energy conservation measures.
- Existing State emission offset rules allow the transfer of offsets between stationary and mobile sources. Expansion of such emissions trading between stationary and mobile sources could provide market incentives for further early emissions reduction.

Recommendations:

▲ Reflect environmental costs in integrated resource planning while encouraging the evolution of market-based forces to achieve environmental goals at the lowest reasonable cost.

▲ Continue to promote the development and implementation of cost-effective DSM strategies which encourage energy conservation.

▲ Require applicants who request a rate

discount to undertake an independent and comprehensive energy audit program before granting a rate adjustment.

▲ Structure energy bidding processes to reward projects which minimize the long-term costs to New Jersey's economy and environment, rather than focusing solely on short-term prices.

▲ Base competitive procurement on principles that are fair and open to renewable resources.

▲ Consider the development of incentives and exploration of alternative environmental approaches to encourage large energy generators and users to set pollution reduction targets above and beyond current minimum standards.

▲ Incorporate environmental policies into energy goals that are designed to efficiently and effectively meet existing clean air and water standards.

▲ Consider aligning tax policy with energy policy and environmental policy and eliminating tax disadvantages for clean fuels.

▲ Incorporate the objectives of the New Jersey Environmental Master Plan, currently under development, the State Implementation Plan for air quality, and the environmental and land use goals of the State Development and Redevelopment Plan into energy policy.

▲ Assess the decommissioning of older, inefficient higher-emitting power plants in favor of more efficient energy generation facilities during integrated resource planning.

▲ Support regional efforts to improve air quality through coordinated solutions, particularly the efforts of the Ozone Transport Commission. As the bulk power market develops into a regional and even national commodity-type exchange, it is important that environmental standards imposed on power plants throughout the region exhibit commonality in order to avoid market distortions.

▲ Pursue a regional emissions reduction strategy, in accordance with the September 27, 1994 Memorandum of Understanding of the Ozone Transport Commission, to decrease the amount of air pollution transported into New Jersey. A regional strategy could reduce the State's compliance costs related to the implementation of the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992.

▲ Endorse the efforts of the Ozone Transport Commission to produce post-RACT reductions in ozone precursors through a cost-effective market-based trading system.

▲ Persue a regional emissions reduction strategy that, by the year 2003, establishes a common region-wide emission limit so that all power plants in the PJM pool are subject to the same environmental standard.

▲ Encourage emissions trading to act as a tool to support DSM. Allow participants in DSM programs to gain credit for verifiable and quantifiable emission reductions.

▲ Work with the Department of Environmental Protection in refining the methodology that the Board of Public Utilities has developed to measure the costs and benefits of energy savings, particularly with regard to environmental benefits.

▲ Work with the Department of Environmental Protection to quantify emissions reduction from conservation measures. Conservation efforts could reduce the projected emissions growth rate, thus becoming an important strategy in the State Implementation Plan for air quality.

▲ Continue to explore with the Department of Environmental Protection, the Ozone Transport Commission, and other State and regional entities, the possibility of expanding the NOx emissions trading program to other pollutants.

▲ Explore with the Department of Environmental Protection the possibility of allowing credit trading between stationary and mobile sources.