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REGULATORY POLICY ISSUES AND THE CLEAN AIR ACT: AN INTERIM REPORT ON THE STATE IMPLEMENTATION WORKSHOPS

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I. INTRODUCTION

The National Regulatory Research Institute (NRRI), with funding from the U.S. Environmental Protection Agency (EPA) and U.S. Department of Energy (DOE), conducted two workshops on state public utility commission implementation of the Clean Air Act Amendments of 1990 (CAAA). The first workshop was held in Charlotte, North Carolina for southern and eastern states in April 1992 and the second was held in St. Louis, Missouri for midwestern states in May. The workshops had four objectives: (1) discuss key issues and concerns on CAAA implementation, (2) encourage a discussion among states on issues of common interest, (3) attempt to reach consensus, where possible, on some key issues, and (4) provide the workshop participants with information and materials to assist in developing rules, orders, and procedures in their state. Of primary interest from the federal perspective was for workshop participants to return to their states with additional background and understanding of how state commission actions may affect implementation of the CAAA and enable them to provide guidance to their jurisdictional utilities. It was hoped this would reduce some of the uncertainty utilities face and assist in the development of an efficient allowance market.

The basic format of the workshops was that invited speakers made presentations on specific issues. "Primary participants" from each state and other workshop attendees then discussed the issues raised by the speakers and other related concerns. The primary participants were state commissioners, commission staff, representatives from state consumer advocate organizations, EPA, DOE, and the Federal Energy Regulatory Commission (FERC). Other attendees were utility representatives, consultants, and other interested parties. All participants were given a workbook with excerpts from an NRRI report on CAAA implementation and papers or outlines from speakers. (This material is not contained in this report, but is available upon request from NRRI.)

As is common with difficult problems, the answers to questions often raise still more questions. An unresolved question that ran throughout the workshops and that continually came up when the various issues were discussed was the uncertainty surrounding the development of the allowance market. Questions for state commissions include: what role should state commissions and FERC play in the allowance market? What can be done to reduce the uncertainty utilities face? Is there any benefit to fostering the market's development? Eventually, nearly every question concerning the regulatory treatment of compliance costs and allowances returned to the market development questions.

To some extent, state commissions and FERC face a "Catch-22" dilemma: if they do nothing to assist the market, utilities are likely to pursue a go-it-alone strategy resulting in compliance costs similar to a command-and-control type of environmental regulation (some have argued that it would be even higher because of considerable uneconomical overcontrol) and the potential for cost savings will not be realized; a deliberate policy to rely on the market, however, may put ratepayers at some risk since there is uncertainty concerning price and availability of allowances. Workshops such as these and other fora provide a means to find ways out of this dilemma.

This report is divided into two main sections. Section II provides a state-by-state overview of events and issues. All the states at the beginning of the workshops were asked to give an overview of their activities with respect to CAAA implementation. Summarized here, in edited form, are the participants' responses. In section III, ten principal issues are identified and discussed. These issues were chosen because they were either the most discussed or related to the questions asked in response to the speakers' presentations. They do not cover all the issue relevant to state implementation nor even all the issues discussed at the workshops.[1] Rather, this report is intended to provide an overview of the planning, ratemaking, and multistate issues.

This is an interim report. Two additional workshops are planned, one for western states and one for New England states. As a result, this report is a working document with an open format to allow for additional responses from states and additional issues that may be identified and discussed.

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[1] For an overview of the Title IV provisions of the CAAA and a more complete discussion of these and other issues see Rose, K., et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program,* The National Regulatory Research Institute, NRRI 92-6, May 1992.

II. REVIEW OF STATE COMPLIANCE ACTIONS

State commission participants were asked at the workshops to give a brief summary of CAAA compliance actions taken in their state. The following state-by-state summaries were derived from those accounts. While this is not intended to serve as a detailed survey of state action, the summaries do provide some background on the types of questions and solutions that states are considering or are using already. The views expressed are those of the individual commissioner or staff member, and do not necessarily reflect the views of their state commission.

Alabama

The Alabama Public Service Commission has had some preliminary meetings with the Southern Company, the only electric utility the Commission has to deal with in Alabama. A phase I plant is located in Alabama and is jointly owned by Alabama Power and Georgia Power--both Southern Company subsidiaries. At the present time, preliminary discussions with the company indicate it is planning to fuel switch to comply. It has not at this point, however, filed a formal plan with the Commission. In earlier meetings, the company and the Commission had more questions than answers on the effects of the CAAA. In addition, how the Commission will deal with allowances and problems with being part of a holding company will have to be addressed and handled.

Arkansas

Arkansas has no specific designated units for phase I and no required action is currently needed for the phase II affected units (that is, no units require a reduction in emissions). Consequently, the focus at this point is on the allowance trading market since Arkansas will have an excess of allowances. Arkansas is in a very different situation than some midwestern states since the Commission has not yet addressed least-cost planning. It is hoped that CAAA compliance and least-cost planning will come together in terms of forecasting in the future.

One of the other issues of concern since passage of the CAAA is the multistate situation.

Arkansas has no intrastate electric utilities; they are all multistate. Two are parts of registered holding companies. Thus, of particular interest is how allowances will be used or allocated in states like Arkansas where ownership of those allowances may be with plants in another state but ratebased in Arkansas.

Another issue is multiple ownership. All of the units that will have allowances in Arkansas are owned not only by an investor-owned utility (IOU), but also a generation and transmission rural electric cooperative and several municipalities. Also, the Commission anticipates addressing confidentiality as the allowance market evolves.

Delaware

The Delaware Public Service Commission is at the meeting and preliminary stage on this issue. Delaware regulates one electric utility involved with the Clean Air Act--Delmarva Power and Light Company. Delmarva intends to meet its requirements by fuel-switching except, of course, with its share of the Conemaugh plant. Also, the Commission is preparing an integrated resource plan; there have been no specific filings from Delmarva yet. They are, however, expected to file one this summer.

District of Columbia

The District of Columbia has no coal-burning plants. Nonetheless, D.C. will incur some of the cost of PEPCO's Maryland compliance strategy, which is primarily at the Chalk Point plant, and PEPCO's part of the Conemaugh plant in Pennsylvania that is now constructing a scrubber.

The Commission holds the view that compliance ought to be handled as much as possible within the least-cost planning process. However, D.C. is not as far along as Maryland on whether the capital cost of compliance should be handled on an energy basis or as a general capital investment. The Commission has some indication of PEPCO's initial compliance strategy. Generally, the Commission would like to work closely with the utility (the District's only electric utility).

One concern is accounting for potential sales of allowances. If, for example, the company has made capital investments to generate allowances (such as Conemaugh) that sells allowances to another firm, ratepayers obviously should share in any benefit. The Commission has not addressed this question yet, but will shortly. There also has been a lot of concern over the alleged failure of the allowance trading market to develop. However, EPA has not finalized its rules and, moreover, all markets take time to develop. This is not going to be an exception, thus, some patience is called for to allow utilities to recognize that allowances have value to others and for the parties to negotiate and trade them.

In D.C. the core approach is to try to work as closely as possible with the utility so that when the time comes for approval of a compliance plan, a least-cost plan, an allowance trade, or the setting up of a trading system, the company and the Commission already will have worked out the basic problems.

One interesting feature of the CAAA is that this is a major case of internalizing an environmental externality. The Commission has been concerned about how to consider the many environmental externalities of a utility. This Act solves part of the problem by internalizing those costs.

Florida

Legislation was just passed that allows the Commission to give a utility prior approval, which means that the Commission may approve a compliance plan and allow cost recovery. The bill does not indicate whether cost recovery should be in the middle of a rate case, between rate cases, or pursuant to a cost recovery clause, but merely indicates that the utility can recover its costs for complying with the CAAA. The legislation contains no language concerning the transfer of risk from the utility to ratepayers from prior approval, and there is nothing in the legislation about conservation as a compliance option.

There may be a problem since (as with most states) the current commission cannot bind future commissions. That is, in a legal sense, the present commission cannot order a utility, for example, to install a scrubber which will, with absolute certainty, be put in rate base upon completion. Future commissions still may overturn such decisions. However, if a future commission were to overturn an earlier decision, it could be overturned by the courts.

The two phase I utilities in Florida are Tampa Electric and Gulf Power Company. Because of the uncertainty in the market they may opt for low-sulfur fuel in the beginning and then scrubbers once the allowance market develops. Approval of a low-sulfur fuel contract is not too different from any other approval that has been done for many years with the fuel adjustment clause (FAC). In that sense, the CAAA does not make that much difference in that form of prior approval. The real test, however, will come when the utility makes capital investments since once a capital investment has been made that investment stays for fifteen, twenty, or thirty years. Florida has no force majeure, no escape clause, and no contract reopener, which is going to be tougher to deal with. Because of the uncertainty in the price of fuel and the price of allowances, installation of a scrubber may be too risky.

Georgia

In 1991, the Georgia General Assembly passed an extensive and detailed integrated resource planning (IRP) statute. The Georgia Public Service Commission then passed rules that impose detailed requirements on the companies. Integrated resource planning currently is under consideration by the Commission, which regulates two electric utilities in Georgia. Both are subsidiaries of the Southern Company--the largest subsidiary of the Southern Company is Georgia Power Company and the smallest is Savannah Electric, so the Commission has to deal with an extreme size difference between utilities.

Some coal-fired Georgia Power Company plants subject to the CAAA requirements are jointly owned by rural electric cooperatives and municipals. As mentioned, currently there are filings before the Commission under the IRP docket, including plant and demand-side certification. Each includes some prior approval. In February 1992, the Commission issued a notice of inquiry to consider the trading usage and accounting treatment of allowances. This includes the rate treatment of the allowances applied to Georgia Power and Savannah Electric. Comments have been received from the utilities and are currently being considered. Reply comments are expected in a couple of months. The Commission is committed to working with utilities, ratepayers, and parties representing the ratepayers--interveners, the consumer's counsel, and other state agencies--in working out a fair and reasonable rate treatment for the allowances including the trading of allowances. The intention is to have the cost to consumers be as low as possible, but also treat the company in a fair and reasonable fashion.

Illinois

State legislators in Illinois have set public policy regarding scrubbing versus fuel-switching in the state for two utilities. Consequently, the Illinois Commerce Commission knows already what is going to happen to these phase I plants in Illinois. Two IOUs have their compliance strategies mandated by the statute requiring scrubbing, and is a major part of their phase I compliance strategy, but not all of it. Another utility will comply by using Illinois-mined low-sulfur coal that is less expensive than its current Illinois high-sulfur coal under a long-term contract. A fourth utility is in compliance. The statutory mandate assumed a considerable amount about the value of allowances when making the decision to mandate scrubbing.

Strategies such as hedging are likely to be used by some utilities in the state which will be trading allowances. A unique situation with one utility is that even though it is not going to be using scrubbers for compliance, it has an option because of a rule that it was able to promulgate at the EPA to generate allowances by bubbling two plants. One plant has a scrubber that can significantly overcontrol while the other is currently on compliance coal and is a new source performance standards (NSPS) unit.

On the issue of the Commission's decisions being binding, Mississippi River Pipeline Company versus the Illinois Commerce Commission says that decisions of the Commerce Commission are not binding. The Commission does not have a res judicata status in terms of other laws. However, the Commission believes firmly in the value of the regulatory compact and meeting its commitment in that area.

The Commission has given some consideration to the regulatory treatment of allowances, including the implications of carrying them as a straight inventory versus an asset held for future use. The Commission has also reviewed and filed comments on the FERC's proposal on the accounting treatment of allowances and the IRS's recent request for comments on the tax treatment of allowances. Basically, the Commission supported the FERC proposal for revisions to the Uniform System of Accounts and recommended adoption of an historical cost standard. There has been talk (outside the Commission) concerning fair market value and opportunity cost. Internally, treatment of allowances has been discussed not within the historical cost-accounting model but through the dispatching of the plants. There would be an opportunity to deal with the marginal cost of allowances at fair market value, then the proper economic decisions would be made through the fuel clause.

Another issue is dealing with the regulatory framework in Illinois, is that it would appear that the ratepayers are going to be paying the cost of compliance. A question that comes up with respect to incentive regulation for CAAA compliance is why, for example, should the utility's shareholders be given an incentive if the ratepayers are absorbing all of the compliance costs?

Indiana

In Indiana many utilities face very large phase I requirements, including substantial capital and operational costs and considerable unknowns. One utility in particular took the lead in getting Senate Enrolled Act (SEA) 514 passed last year, which allows preapproval of environmental compliance plans. Towards the end of last year or the beginning of this year, Southern Indiana Gas and Electric Company and Public Service Indiana filed under SEA 514. Indiana Power and Light (IPL) also filed recently, so there are currently three major cases in which the Indiana Commission is very much involved.

The utilities also have been active in integrated resource planning, specifically in the area of demand-side management (DSM). In addition, Indiana is faced with the forecasted need for additional capacity in the mid to late 1990s. Therefore, ratepayers in Indiana will be affected greatly and concurrently with the requirements of the CAAA.

Indiana has an environmental construction work in progress (CWIP) statute and no CWIP for anything else. SEA 514 is voluntary in nature and so far three of the major utilities have decided to take advantage of it. If a utility requests that certain information be deemed confidential, there is a procedure to deal with confidentiality issues.

Another aspect of 514 is that there is a large Indiana coal bias. A question is, how does this affect the emissions allowance market? Also, another concern is risk and rate of return. Under 514, the Commission is asked to give due consideration to any change in risk to the public utility as a result of the Commission's approval of the plan. It does not say the Commission "shall" do anything, but only give "consideration." There is also the issue of flexibility. The utility can retain flexibility through modification of their plans from their own initiative, the Commission initiative, or possibly from another party's. A future Commission, therefore, is not necessarily bound by the current Commission's decisions. There is guaranteed cost recovery, absent fraud or concealment of gross mismanagement.

While resources of the Commission are limited (and they will always be limited), the Commission is not precluded from trying to work with the statute.

Iowa

Iowa has been active in the rulemaking process before FERC and the EPA. The activities have been focused through working groups in the state with members from the Iowa Utilities Board, the Office of Consumer Advocate (OCA), and utilities within the state. Iowa has many investor-owned companies with seven electric generating companies and six affected units. Several companies have already switched to western coal or low-sulfur coal from other sources. At this point, there are no companies considering the possibility of scrubbers.

In Iowa, preapproval is not an option by statute. Rather, participation in the working group provides guidance or direction to utilities prior to any review of prudence. The Board's view, while not yet final, will probably be in connection with the annual fuel procurement review.

A problem that will likely come up in Iowa is joint ownership. There is a large number of multiple owner facilities and at this point it is not clear what action will be taken or what all of the problems are. Confidentiality has not come up, but is addressed in the annual reviews on a case-by-case basis.

Kansas

Kansas is a somewhat clean state that switched to Powder River Basin coal for the most part and has scrubbers. The Commission has not yet addressed comprehensively the issue of IRP but is currently looking at CAAA compliance as an integral part of the pending IRP docket.

There are some peculiarities in Kansas which are going to affect how the Commission looks at some of the CAAA issues. One is that most Kansas utilities do not have an automatic FAC. Also, there are some precedents for reward sharing or incentive types mechanisms in cases where there is risk sharing. The Commission has been asked to address the issue of preapproval by at least one utility; the Commission, however, has not yet acted on that request.

Kentucky

Kentucky, even though it is a semi-dirty state, has had only minimal activity in the area of CAAA compliance. In early 1991, the Commission opened Administrative Case 339 where utilities were asked to file their compliance plans. It was found that at this point everything was preliminary and the Commission has not yet taken any further action in the matter.

For the last couple of years, there have been ongoing IRP cases which were filed on a staggered basis by the utilities. Sometime this fall the Commission plans to issue a statewide perspective on the filings. There has been no decision at this point as to whether or not CAAA compliance will be incorporated into the process.

Over the last ten or fifteen years utilities have been scrubbing all their new generation plants. One utility has one plant affected by phase I and has put an application before the Commission for a certificate to scrub one of their units. That application was filed in a traditional manner and the Commission is currently considering it. Kentucky also has allowed CWIP in rate base for some time. Also, there is an FAC and the legislature (which convenes every other year and was in session this year) passed an environmental surcharge bill which will allow electric utilities investing in environmental equipment to begin immediate cost recovery through an environmental surcharge. All these factors have come together to slant Kentucky's utilities toward the scrubber option. There has been very little activity or discussion about allowance trading, buying, or other available options.

Louisiana

While Louisiana is on the outermost periphery of a coal area, there are only less than half a dozen coal-fired units, all of them relatively small. There has been a local depression since 1985.

Three new nuclear plants recently came on stream and as a result, at the present time, a 300 MW 1970's-vintage gas-fired plant has been mothballed for which gas could be purchased for probably $1.20 or $1.30 per Mcf. Down the road, there will be cogeneration prospects, so no one projects any need for new capacity of any kind until sometime in the late 1990s. As a result, there have been very few filings or interest in CAAA compliance.

Maryland

On approaching the CAAA, the Maryland Public Service Commission has decided to try to keep the lines of communication open between all affected agencies. When the Act was passed, all utility companies were asked to provide the Commission with preliminary thoughts as to how they would go about complying with the Act. The responses, however, contained so many questions that it was impossible to draw any concrete conclusions. For the second year, the Commission is making compliance planning a part of the IRP data request and will be dealing with compliance plans within that context. Maryland also established a coordination counsel consisting of the Maryland Department of Natural Resources, the Commission, and the Departments of

Energy and Community Development to address the issues associated with bringing the state into compliance with the CAAA. Maryland has a significant nonattainment area for ozone. As discussions continue, this has been identified as having a major impact on the state's utilities. For example, one utility has found that the potential cost of complying with NO_x requirements will dwarf the amount of money that it will have to spend to comply with the SO_2 (Title IV) requirements of the Act.

The Maryland Commission regulates Potomac Edison Company, which is part of the Allegheny Power System. Potomac Edison brought its compliance plan to the Commission in the form of a rate case. From that proceeding it was decided initially that even though scrubbers are a capital investment, the appropriate methodology for allocating those costs is on an energy basis, which has jurisdictional and class cost-of-service implications.

The Commission is now in the second phase of responses from utilities concerning their compliance plans. Potomac Electric Power Company is expected to apply soon for Commission review of its compliance program. The other two utilities--Baltimore Gas and Electric (BG&E) and Delmarva Power and Light--have not yet indicated their plans to the Commission. There are currently so many questions still outstanding--the tax implications of allowance trading, direction from EPA on what the states are going to have to file for their state implementation plan, and so on--it would be counterproductive to bring a utility company in to discuss their compliance plan when there are simply so many issues that have not been resolved at this point.

In the IRP area, the Commission is requiring that all utilities, by the end of this year, have comprehensive demand-side programs in place. The Commission is removing regulatory barriers to demand-side programs by compensating utilities for lost sales. Also provided are explicit incentives for most utility companies to engage in demand-side planning. The Commission is currently involved in a collaborative process with all four major electric utility companies. One major objective of this effort is to develop a data base to determine the efficiency of demand-side programs and expected energy savings from utility-initiated conservation activities.

Michigan

Michigan has two major utilities, both in effect phase II utilities. Detroit Edison is in fact a phase II utility company and Consumers' Power Company, although it did have two units on the list of 110 plants (designated phase I plants in the CAAA), some fuel-switching has occurred and they are now in compliance with phase II requirements. As a result, there has been no formal statement of policy by the Michigan Public Service Commission in the form of generic orders or specific cases dealing with the CAAA. There has been some activity, however, with the IRP process. In a recently reviewed Detroit Edison plan, fuel-switching was the preferred option.

On the confidentiality issue, Michigan has a strong Freedom of Information Act and if someone gives the Commission information, it will be considered public.

Minnesota

Minnesota has only one phase I-affected plant, which is relatively small. As a result, there is not a lot of immediate activity in the area of CAAA compliance. Minnesota has had prior state emission laws so several utilities already are using scrubbers and many are using western coal. There has been an FAC in place in Minnesota for several years. Minnesota is beginning resource planning reviews. There has not been any decision as to whether CAAA compliance can or should be rolled into the resource plans.

In late 1991, several work group meetings were held with Commission staff, utilities, and other interested parties. There was discussion of the many questions surrounding the implementation of the CAAA, but the general consensus of the group was that for Minnesota it was too soon to begin making any decisions. The Commission opened a docket, but there has been very little activity, although, it is expected that later this year things will begin to happen. There has been no official discussion on preapproval, but there continue to be informal meetings to maintain communications. Action by the Commission is pending further development and evaluation of the Board of Trade's activities, EPA and FERC rules, proposals by the utilities, and developments in neighboring jurisdictions.

Minnesota has a method of filing for confidentiality with the Commission, so it is not expected to be a particular problem.

Mississippi

Mississippi has relatively clean utilities and therefore does not have a pollution problem as such. There is only one small utility company subject to the CAAA--a small subsidiary of the Southern Company. Mississippi Power Company has an innovative incentive regulation plan, but unfortunately it was not designed to deal with the kind of capital expenditures required to comply with the Clean Air Act Amendments. The company, however, has filed and the Commission is currently reviewing a capital cost recovery plan that deals with continuous emission monitoring systems (CEMS) and low nitrogen oxides (NO_x) burners that are required to be installed initially.

As with other subsidiaries of the Southern Company, Mississippi Power Company plans to use low-sulfur coal initially, accumulating some allowances in phase I and are less specific on what they plan to do in phase II. Recently, however, they have asked to delay some of the capital expenditures (such as some precipitators) because they are reviewing cofiring of the units with gas. They have indicated that they will not know about long term contracts until this summer. This does provide the Commission with some flexibility.

Missouri

On the confidentiality statute, the Commission staff developed an extensive questionnaire early on in the Clean Air Act and discussed it with the utilities. The Commission may not have received any responses had it not been filed under the confidentiality statute on the books in Missouri. Utilities are quite concerned about fuel costs, rail contracts, and when fuel contracts expire. Some of the questions asked were what coal are they going to be burning and will they be using allowances? It was the Commission's opinion that it be asked under the confidentiality clause to get the information.

On the question of binding preapproval Missouri went through some nuclear plant phase-in in the mid-1980s. While the Commission did not have a complete turnover of Commissioners, there were some changes, but the phase-ins that went out several years ago were never challenged by future Commissioners. Fortunately, the Commission was able to end the phase-ins early.

There has been much discussion on the banking of allowances and the accounting issues of what happens if the utility keeps them and the price goes down or sells them and the price goes up. In Missouri, fortunately, the Legislature is not telling the Commission what to do. There is a small coal mining industry in Missouri, with one power plant, owned by Associated Electric, that depends on Missouri coal. Right now it is investigating whether it should switch to low-sulfur coal or not.

Kansas City Power and Light has filed its compliance plan with the Commission. Basically, it asked for (1) approval of the plan, and (2) if it wants to buy or sell allowances, does it require Commission approval? This is because there is a statute that basically says any time a regulated utility buys or sells anything, it has to have approval from the Commission. The Commission staff's opinion is that approval should not be required every time a utility buys and sells allowances. If the legal department believes the statute is applicable, the Commission staff may encourage a blanket approval.

There is currently an IRP proceeding going on. The Commission does not see how compliance planning can be considered outside of an IRP proceeding. Preapproval has been a hot topic in that proceeding. There will be another draft of the IRP plan in a few weeks.

Utilities in Missouri will be fuel-switching. Western coal can be delivered for about $1.00 per mmBtu. Illinois coal was about $1.40 per mmBtu and local coal used in one plant is about $1.50 to $1.60 per mmBtu. The addition of scrubbers on top of higher fuel prices does not seem reasonable when trying to provide least-cost service in a competitive environment. As a result, there should not be any major rate cases in Missouri as a result of compliance.

Although Missouri has a number of jointly-owned plants, it has not yet been an issue before the Commission concerning how allowances would be handled. This issue may be resolved by the contract that the various owners have in the plant.

New Jersey

In New Jersey there have been for a number of years sulfur and fuel limitation statues and rules. That in combination with geography leaves New Jersey with a fairly small amount of coal generation. There are three coal plants in the state, two of which are in marginal compliance with phase I and II. They use low-sulfur coal and one unit has always received an exemption from the state's sulfur fuel requirements--the Atlantic Electric's B. L. England plant. However, it is affected by phase I and Atlantic has indicated that it is planning to scrub the plant. In 1990 and

1991 there was a series of meetings that included members of state utility commissions and air quality commissions from the PJM area (Pennsylvania, New Jersey, Maryland, Delaware, and D.C.). The meetings provided an opportunity to exchange information on compliance plans--or at least preliminary compliance plans--among the different jurisdictional utilities. The process allowed a sharing of information and an opportunity to discuss integrating plans and coordination. Some potential areas where coordination may be helpful were identified. It appeared at first that utilities were taking an approach of looking out after their own needs only; that is, generating sufficient allowances to cover their own internal needs. However, there may be opportunities for compliance planning on a regional basis if looked at in more detail. The process has been rolled into a project cosponsored by DOE and EPA on PJM power pool integrated resource planning.

New Jersey has adopted regulations which provide revenue neutrality for utilities that invest in conservation measures and comprehensive guidelines for conservation plans, including incentives for adopting DSM programs. Plans have now been filed in response to the regulations and are currently under review. Data is one of the key issues in conservation and the Commission rules emphasize to a large degree measurement verification of DSM savings, which will then be used as the basis for paying incentives to the utilities. It is hoped that the rules will justify the incentives and satisfy DOE if the utilities ask for certification for conservation bonus allowances.

Right now New Jersey does not have any specific rules for compliance plans and the utilities have been fairly silent on this. As mentioned, Atlantic Electric is proceeding with plans to scrub B. L. England and there have been some discussions with the state air quality agency. These discussions demonstrate, on a small scale, some of the issues that come up because the state air people are very concerned with the local airshed that is near the B. L. England plant. They have been making it clear to the utility that scrubbing would be the best option from a local air quality point of view. From an economic point of view, it does not seem as clear and it is not an obvious application for scrubbing. It is certainly not a cheap application.

There are ongoing discussions inside the state with regard to plans for implementing rules on compliance. This will most likely be rolled into the IRP process. New Jersey is starting an integrated resource review plan to convert the certificate of need proceeding, which is now the review process for individual new plants being constructed, to an IRP process that certifies the needs of the utility then designs an IRP process. The compliance plan approval process would be rolled into this new process. Preapproval, however, is inconsistent with what the Commission has done in the past.

New York

In 1984 New York enacted a Sulfur Deposition Control Act which demonstrates a strong interest and New York's economic stake in air quality and the resources that it wants to sustain.

In January 1992 New York initiated a formal proceeding to deal with the implementation of the CAAA and brought together all the parties and interests--the utilities, EPA, and others. The purpose of the meeting was to bring the various parties together early in the process to try to put the different interests, views, and concerns on the table. The three utilities in New York that are directly involved in phase I are Long Island Lighting Company, New York State Electric and Gas, and Niagara Mohawk. Other utilities will be included in the process later on. In addition to the Commission, the State Department of Environmental Conservation as the state air agency in New York has a very important stake in these proceedings. So it is very important that some type of opportunity be afforded to ensure that the utilities and the Department of Environmental Conservation (as well as the State Energy Office, which had the lead role in developing the state's energy master plan) should also be part of this process.

There have been a series of somewhat informal meetings and New York is now ready to take the next significant step. Within the next couple of months the Commission will put out for comment a series of questions that will focus on matters of special concern; a major concern revolves around the Adirondacks. Thus, one principle that emerged soon after the Clean Air Act was the concept of "deposition neutrality." This has had a chilling effect upon the ability of the utilities to proceed with their plans--particularly those that include the sale of allowances.

Basically, the concept of deposition neutrality holds that if a utility were to sell allowances it should do so in a way that the result would be neutral with respect to the resources of New York--a very tricky question. However, the utilities have been working closely with the Department of Environmental Conservation and Commission staff has been involved in discussions. The issue was raised to a higher level when Governor Cuomo wrote to EPA's administrator on this issue in August of last year (1991), which made everybody even more nervous about the impact of this on future policies. Because of a very strong regulatory separation of issues and concerns in New York, the Department of Environmental Conservation--the air agency responsible for many of the enforcement elements of Title IV as well as the other key parts of the Clean Air Act--it will be necessary for the state agencies to all be involved in the regulatory process so that "the one hand does not give and the other take away." One way is under the broad umbrella of the State Energy Master Plan. The Governor has directed that the Chairman of the Commission, the Commissioner of the Department of Environmental Conservation, and the Commissioner of the State Energy Office work together to ensure that the State Energy Master Plan, which was then in its final draft, would be sure to reflect some kind of consistency. This will help ensure that the kinds of concerns that were before the Commission regarding the Clean Air Act can be addressed effectively.

The Commission also has a long tradition of involvement in demand-side management, energy conservation, and the elements associated with revenue neutrality, resource planning, and the like. So there are many types of interrelationships that are involved and being addressed in a direct manner.

North Carolina

North Carolina has no phase I plants. Because of this, the North Carolina Utilities Commission has not been very proactive in the area of clean air compliance yet. However, the utilities and the staffs of the Commission and the Attorney General have had some preliminary discussions.

Not addressed so far is how to handle the specifics of compliance planning. North Carolina does have both a load forecast hearing and a biannual IRP hearing. Compliance questions may be addressed in an IRP hearing coming up this fall.

North Dakota

North Dakota sits on a vast reserve of lignite coal, a low-Btu coal that is also low sulfur. Since it takes a lot of it to burn, there may be some NO_x problems. As for SO_2 problems, North Dakota is in good shape. There are no phase I units and five affected phase II units. Of those five phase II units there is very little reduction required. There will be a surplus of allowances in the state.

One of the reasons North Dakota is in good shape is that three-fourths of the state's coal-fired generation has already been scrubbed. Of total generation, one-eighth is hydro. There is also a fluidized bed unit. Fluidized bed units for repowering old capacity should not be overlooked (rather than just looking at scrubbing).

Because of the state's good position, it is too early to make any decisions or implementation strategies for the CAAA. The Commission has scheduled an informal workshop for July 15 and has invited all of the utilities which have plants in the state, including the rural electric cooperatives which the Commission does not regulate and some out-of-state producers that export electricity. The intention is to have a discussion and presentation of plans and attempt to familiarize each other with how North Dakota is going to be affected.

Another point that contributes to the state's good position is the excess capacity in the state. There is a slow load growth rate and, at present, export of three-quarters of the energy produced (as far away as California).

On policy options, the Commission has very limited resources and has a very small staff. This makes preapproval an impractical option. In addition, there is a statute that limits the Commission's decisionmaking authority to present decisions and it cannot make commitments for future Commissions.

Ohio

The Ohio Public Utilities Commission views the allowance trading provisions of the CAAA very positively. The Commission believes that there can be real cost savings and efficiency improvement from this aspect of the law. Soon after the passage of the Act, the Commission issued a declaration which indicated it expected Ohio utilities to use allowances and allowance trading as a part of their compliance plan and that the Commission would not view positively the uneconomical or inefficient hoarding of allowances.

In addition, the Commission has been active with periodic meetings with other state commissions that regulate operating companies of American Electric Power (AEP). The Commission has been trying to at least have open lines of communication with respect to the implication of the Act and believes that even if some general agreement on how AEP should be treated relative to its compliance cannot be reached, that at least having these lines of communication open and active is likely to improve the process.

In 1991, the Ohio State Legislature passed Senate Bill 143 which essentially provides for preprudence or preapproval of the decisionmaking relative to CAAA compliance. Use of the law's provisions by utilities is voluntary. It permits, through meeting the requirements of the law by a filing with the Commission, a preapproval of compliance decisions. This does not include upfront cost recovery and it does not eliminate an examination of the prudence of the actual expenditures undertaken. The Commission still has the ability to take action when, for example, two tons of concrete were used when one ton would have done the job.

Another occurrence relative to the CAAA in Ohio is that in early 1991, AEP filed with the Commission and made public a plan in which it proposed to fuel-switch at the Gavin generating plant's two 1,500 MW units. The Commission asked it to file information on its proposal and in September 1991 the Commission ruled that AEP should keep open the option of scrubbing as well as fuel-switching at the Gavin plant. This was because it was not clear from the analysis provided that fuel-switching was the least-cost alternative.

In January 1992, the Commission initiated a Commission Ordered Investigation, which was sent out to interested parties, with twenty-two questions dealing with the accounting and trading of allowances. The reply comments were all received by May 5th. The staff is in the process of analyzing those comments and is currently developing rules, regulations, and procedures relative to allowance trading and accounting for allowances.

The primary way in which the Commission in Ohio intends to review the compliance plans of the utilities is through their long-term forecast filings. The Commission has a requirement that utilities make long-term forecast filings annually. The Commission ordered each electric utility in Ohio to include in its 1992 long-term filing its proposed compliance plan. The intention is to review those compliance plans as part of the long-term forecast and as part of the IRP process. The criteria used to undertake that review, is essentially that the plans should be least-cost on a long-term present value basis. In other words, the Commission is incorporating compliance planning with the IRP process that is in place in Ohio. A number of those fillings have been made with the Commission. On April 15, Centerior made its filings for Toledo Edison and Cleveland Electric Illuminating, as did Ohio Edison. They have not, however, finalized their compliance plans, which will be received, it is assumed, at a later date. On April 30, AEP made its long-term forecast filing for Columbus Southern Power and Ohio Power, the operator of the Gavin plant. The remaining filings are to be made by Monongahela Power about the middle of May and the other two electric companies--Dayton Power & Light and Cincinnati Gas & Electric are to make their filings by the end of June.

The only electric utilities in Ohio that up to this point in time have taken advantage of Senate Bill 143 are the Centerior companies. When they filed their long-term forecast, they also filed under 143 to have the Commission rule on the prudence of their compliance planning process. AEP made a 143 filing for the Ohio Power Company, but not for Columbus Southern Power. Monongahela made a 143 filing much earlier in the year. The staff has reviewed that filing and had the required hearings under the provisions of that law. The Commission has not yet acted formally on the filing.

The Commission staff has also filed comments with FERC in its investigation of the accounting treatment of allowances.

Perhaps the most noteworthy aspect of Ohio's CAAA actions is the view that compliance planning should be a part of the IRP process. This will incorporate the impact of other planning characteristics like demand-side management, and view them through the entire planning process on a long-term basis. Ohio is unique because two of the electric utilities are owned by an interstate holding company--AEP. Also, there is a company that has its primary operations in Ohio but subsidiaries in Kentucky, one that has subsidiaries in West Virginia, and one company that operates entirely within the state of Ohio. So there is a considerable range of electric companies currently developing policies for purposes of complying with the CAAA.

Pennsylvania

It has been estimated that from the period 1995 through the year 2000, Pennsylvania utilities will incur $2.5 billion in capital costs for SO_2 and NO_x limitations. Also, annual revenue requirements are estimated to be in the range of $760,000 for SO_2, NO_x, and waste disposal.

On March 19, 1992 the Pennsylvania Public Utility Commission decided its first CAAA implementation case. The case involved West Penn Power Company, a member of Allegheny Power System (which also includes Monongahela Power Company and Potomac Edison Company). The company came in with a declaratory order for preapproval of its plan to scrub three Harrison units in West Virginia and also asked for recovery of CWIP through a surcharge. The total estimated cost of scrubbing the units is $726,000,000. West Penn Power's share (just under 43 percent) was $310,000,000.

The Commission found that it did have authority to preapprove the prudence of the company's plan to scrub its three Harrison units. The Commission used a number of statutes, including the statute to determine just and reasonable service and rates, as well as its general administrative powers over public utilities and its right to register securities for Pennsylvania utilities. The Commission used a "reasonable person standard" in determining prudence. In other words, it stated that prudence is that standard of care that a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the times decisions had to be made. The Commission made no finding with respect to the conduct of construction or the financing of the project. The Commission stated that West Penn Power will be evaluated on its efforts to explore and take advantage of financing opportunities that lower revenue requirements and on the conduct of the construction of the project.

The Commission also stated that West Penn Power had not supported a need for rate relief at this time and that the proceeding did not provide a close scrutiny of the company's overall financial health. The Commission stated the company could have filed a base rate case which would have allowed for the more comprehensive review of its financial situation. Since the scrubber project is subject to section 515 of the Public Utility Code, the Commission will monitor the construction cost and have access to the construction documents. The Commission made no determination on the allowances or who would derive the benefits from them. The company is to refile with the Commission at the time when it receives its allowances. At that time the Commission will also examine the status of the situation with respect to clean coal technology as well as the cost of coal.

Senate bill 1331, which was approved by the legislature and is presently awaiting the Governor's signature, does clearly provide the Commission with the authority for preapproval. The bill states that phase I compliance plans are to be submitted to the Commission on or before February 1, 1993 and that the utility may request approval of the plan. Phase II compliance plans are to be submitted to the Commission on or before January 1, 1996 and the utility may likewise request approval. If approval is requested, the Commission will determine whether the plan is in the public interest. After notice and the opportunity for a hearing, the Commission is to approve or disapprove the plan within nine months after the plan is filed. Approval may be in whole or in part and may be subject to limitations and qualifications. Compliance costs are recoverable if (1) they are prudently incurred costs as determined in an appropriate rate or other proceeding, and

(2) they represent investment in flue gas desulfurization devices, clean coal technologies, or similar facilities designed to maintain or promote the use of coal, including facilities which intermittently or simultaneously burn natural gas with coal.

The recoverable cost of the second part shall qualify as nonrevenue-producing investment to improve the environmental conditions under section 1313--the CWIP statute--provided that any benefits to the utility generated by the sale of allowances under the CWIP will flow through to the utility's ratepayers. Finally the Commission, on March 19, 1992, has instituted a generic investigation into the trading and ratemaking treatment of allowances.

South Carolina

South Carolina does not have any phase I plants, so there is some time to deal with phase II compliance. To date, there have been no compliance filings by any utility. The Commission has had, and will continue to have, joint meetings with representatives from the utilities and the Commission. Initial IRP filings are due this month after an extended process. The Commission intends to use this process to provide some answers to the problem of compliance and its integration into the IRP process.

Texas

Texas has both interstate holding companies and utilities that provide service only within Texas. It has not been decided yet whether Texas is a clean state. It does meet the statutory requirement as a clean state but the Governor has not yet elected to take advantage of the bonuses that come under that program. There are no phase I units in Texas and the initial assessment is that for phase II there will be a shortfall of allowances but not severe. Every two years as part of a resource forecast process the utilities are required to file forecasts of their demand and how they are going to meet that demand for the next ten years. During the last forecast filing, utilities were asked about their compliance plans for the CAAA. Their general response was that there are no immediate problems with meeting phase II requirements. The problem for Texas utilities may be in meeting the demand that will result from load growth in the state. A number of utilities are projecting the need to add units in the mid or late 1990s and early in the next century. The problem is, of course, if there is a shortage now, how can the demand be met in the future?

The Texas Commission filed comments on the EPA proposed rulemaking. Texas may not have the magnitude of problems that some other states have, but one of the issues that was commented on was the continuous emissions monitoring. This is going to be costly. Utilities in Texas want to avoid some of the cost of the SO_2 monitoring for natural gas plants. The SO_2 emissions of a natural gas plant can be determined by simply assaying the gas before it goes into the plant.

The staff of the Commission has looked at requiring utilities to file reports of allowance transactions after the fact. The Commission under current law does not have any authority to control allowance transactions, but the staff view is that the Commission should know what the utilities are doing. An additional benefit to requiring these filings is that it may also have some public benefit of getting information on transactions out to the public including the price the utility paid or received for allowances.

Another issue that the staff is looking at is regulations that would facilitate utilities in Texas applying for the conservation and renewable bonus allowances. There is a continuing problem involving confidentiality in Texas. This has not been specifically addressed it in the context of the CAAA, but the issues are not different from the issues that arise in a rate case.

One issue that may be somewhat unique for Texas is that there are utilities that sell or contemplate selling electricity to Mexico. The Commission may have to make some special provisions for how the utility accounts for allowances in those sales to Mexico.

Virginia

While Virginia does not have any phase I units in the state, there are phase I utilities. In response, the Virginia State Corporation Commission has established a multidisciplinary staff task force. Its charge was to review the acid rain compliance plans for each of the affected utilities and report back to the Commission. The task force found that Virginia Power, the largest utility, is committed to scrubbing the Mt. Storm unit located in West Virginia. Also, Virginia Power issued a Request for Proposal (RFP) in an effort to try to get a feel for the allowance market. The RFP did not result in any purchase of allowances. The fact that the company expressed an interest, however, in purchasing allowances indicates that they do not feel constrained by Virginia regulation from viewing allowance purchasing as an option to CAAA compliance.

Virginia Power has a relatively large amount of nuclear power and this complicates matters somewhat. There have been some unexpected nuclear outages in the past which lasted as long as a year. Obviously an unexpected outage (some of them required by the Nuclear Regulatory Commission) of one or more of the nuclear power plants could cause problems with the utility's compliance strategy. Thus, the Commission will be watching very carefully to see what Virginia Power does in terms of ensuring that there are sufficient allowances to compensate for the fact that they are heavily dependent on nuclear power.

Potomac Edison, a member of the Allegheny Power System, has committed to scrubbing the Harrison station. In a recent case, the staff was provided with an overview of the company's compliance plan and the rate relief granted reflected the expenditures that were made as of the date of the rate case. The Commission did not formally say in the order that this constitutes preapproval of all the expenditures associated with scrubbing nor did they say that it constitutes preapproval of a compliance plan as such, but there is ratemaking treatment now in place.

Appalachian Power Company (APCO) is a little bit different. APCO is a subsidiary of AEP. Its Virginia plants are relatively clean so it has no phase I units. But as a member of AEP, the Commission would like to determine whether AEP has committed to scrubbing its system. When first reviewed, fuel switching appeared to be the least-cost plan. The Ohio Commission, however, has applied pressure on AEP to keep the scrubbing option open at AEP's Gavin plant. To date, this has cost the company $56,000,000. A primary concern at this point is that if the utility does not in fact scrub, who pays the $56,000,000?

Next, the compliance task force will try to generate a staff dialogue with other commissions, especially Ohio given the fact that there has been substantial expenditure for what may not be a least-cost compliance plan. Also of concern is the allocation of compliance costs in the AEP system. If the Gavin plant, for example, is dispatched to serve Virginia load, is APCO required to compensate Ohio Power for allowances that were consumed as a result of that dispatch? Another question is, if APCO needs allowances, and if it gets them from Ohio Power (another AEP subsidiary), will it be required to pay for them? While the obvious answer might appear to be yes, APCO may be required to pay at least a portion of the associated scrubbing cost. Without scrubbing the allowances could not be freed up and marketed.

The Commission is also trying to establish a closer relationship with the Virginia air board. In the past, they have not participated in regulatory proceedings. Currently, they are participating in the certificate process for a power production proposal for northern Virginia. The Commission expects to have an ongoing dialogue with the air board in the future in an effort to make sure that if there are disagreements on some issues, knowing the disagreements at the outset will assist in the development of a united approach to Clean Air Act compliance.

The Commission has not formally preapproved a compliance plan. Virginia does not formally preapprove least-cost expansion plans as of this date. The Commission's perspective has been that the utility's job is to figure out how to expand the system in a least-cost fashion. The Commission is, in effect, a surrogate for competition.

West Virginia

West Virginia is a coal producing state, its biggest industry, and produces natural gas.

The coal is both high sulfur and low sulfur; the northern part of the state is primarily high-sulfur coal, and the southern part of the state is low-sulfur coal. There are no nuclear power plants. The plant that the West Virginia Public Service Commission has addressed so far is the Harrison power plant. Harrison is in the northern part of West Virginia, in the high-sulfur coal area. It is a mine-mouth type of facility, that is, the coal fields are right next to the plant. It is jointly owned by West Penn Power, Potomac Edison, and Monongahela Power Company (which serves West Virginia where the sight is located).

The Commission has approved the construction of a scrubber to meet compliance and it is presently under construction. When the plan was announced that Harrison would be scrubbed, and the application was made for authority to build the scrubber facility, the natural gas industry intervened in the case and contended that compliance would be less expensive with natural gas. The solution was (and all the parties agreed) for Allegheny Power System to use more natural gas as ignition fuel rather than oil. Construction is now under way. (In fact, construction of the scrubber had already started before the controversy came up.)

The Commission agreed that it would allow CWIP at an annual review. West Virginia has an annual net energy review rather than a monthly or annual fuel review, where the whole cost of power, including all system sales, is reviewed. The Commission ordered the company to defer the revenue from sales of allowances for treatment in the annual review. The Commission has deferred the decision on whether the allowance revenue should go directly to ratepayers or at least some portion of it.

An incentive market plan, such as the allowance system, may require an incentive to be given to the utility. As with telecommunications incentives, there has to be something in it for the utility for it to work. A solution to the problem may require that state regulators consider providing incentives or the allowance market may not develop.

The Gavin plant, located in Ohio, will affect the seven states that the AEP serves. West Virginia ratepayers will, of course, share the cost of compliance for the Gavin plant. AEP tried to get all the parties that may have a concern in the compliance decision for the Gavin plant into a public forum. At stake is the displacement of Ohio coal miners' jobs. These are, of course, difficult political questions.

Wisconsin

The Wisconsin Public Service Commission met with all the state's utilities both individually and together before the CAAA became law and formed a staff team within the Commission, composed of auditors, planners, engineers, and legal staff, to make sure that every aspect of the CAAA is considered. The Commission has a very cooperative relationship with the utilities involved in implementing the CAAA. Because of this positive relationship, the Commission has been able to trade information and learn from each other. For example, some of the Commission's staff met with representatives of Wisconsin Electric Power Company to review the proposed FERC accounting rule and some other aspects of their plan on a very informal basis. This kind of interaction tends to benefit both the utility and the Commission staff.

As for confidentiality, the Commission and utilities recognize that this is a significant issue. Wisconsin does have a very strong Public Records Law. For example, the Commission does not necessarily allow anyone in to see the coal contracts of an in-state utility. There is a recognition of the need for some confidentiality and if a utility indicates that something is being provided on a confidential basis (of course, that's not necessarily a public record) it becomes, in effect, information only available to the Commission staff. The Commission also recognizes that utility planning in Wisconsin is a public process and that intervenors and other interested parties are going to want to have some knowledge of utility projections and other things so that they can, as they examine utility plans, have some knowledge and background as to whether or not those plans are reasonable.

Each of the major utilities in Wisconsin does have phase I affected units. However, Wisconsin passed an Acid Rain Control Act in the mid 1980s and that Act requires that all utility units meet a cap of 300,000 tons per year. That cap is currently in effect. Also by 1993, all utility units must meet a 1.2 pound per mmBtu limit by 1993. As a result, the utilities and the Commission staff have been investigating and analyzing a lot of different options for meeting that 1.2 pound cap. Given Wisconsin's geographic access to western coals, fuel-switching has become the option for meeting the requirements of the CAAA. It is expected that compliance plans will become part of our least-cost planning process. The Commission is presently in the final stages of the sixth "advance plan process" and is making preliminary decisions on CAAA implementation.

In general, the staff does not view incentives as being necessary for utilities to engage in cost minimization behavior. It is part of a utility's job to minimize its costs and the need for some kind of sharing with the utility the gains that are a result of ratepayer-incurred costs is unnecessary. The competitive forces that exist with the new open access coming in the transmission system are such that utilities are going to have some incentive to minimize their costs.

III. REGULATORY POLICY ISSUES

A. Compliance Planning and Integrated Resource Planning Issues

- **Allocation of risk, reward, and penalties from compliance decisions**
- **Integrated resource planning and compliance planning**
- **Prudence review of compliance decisions**
- **Preapproval of compliance plans**

Issue: Allocation of risk, reward, and penalties from compliance decisions

Policy Questions: How should the risk of compliance decisions be allocated between ratepayers and the utility? Who should receive the benefit of a good decision or the loss from a bad one? Should special provisions be made because of the current uncertainty of future allowance prices and availability?

Background: There has been a great deal of discussion (at the workshops and elsewhere) concerning the uncertainty surrounding a utility's CAAA compliance decisions. There are three often-cited types of uncertainty associated with compliance planning: (1) market uncertainty which includes the uncertainty surrounding the development of the allowance market (resulting in difficulty in forecasting future prices of allowances) and fuel prices, (2) technological uncertainty that arises from technological change that could render an investment obsolete or from the use of a new technology which may not preform as expected, and (3) regulatory uncertainty which includes the treatment of compliance investments and expenses by state and federal regulatory agencies. These are, of course, the same general types of uncertainties that utilities usually face with system planning independent of CAAA compliance planning.

The first and second types of uncertainty, in the context of the CAAA, stems from the flexibility in the allowance system (which was not present under command-and-control environmental regulation) where utilities now have a wide variety of compliance options from which to choose. However, the compliance decision made by a utility is highly dependant on the price of allowances. For example, examining several options on a dollars per ton of SO_2 removed basis (not, of course, the only criteria used to choose an option), the choices may look like: build a scrubber at $600 a ton, switching to low-sulfur coal at $450 a ton, invest in a clean coal technology at $800 a ton, or purchase allowances at an expected price of $500. If a choice were made simply on this basis, then the switching option would be chosen.

However, purchasing allowances is not only an option to compare with other options, but all the cost estimates of the different options are dependent, either directly or indirectly, on the estimated price of allowances. When a scrubber is installed at a power plant, it usually results in that plant emitting less SO_2 than it receives in allocated allowances, that is, it overcontrols. These allowances can then be sold to offset the cost of the scrubber where the value of the offset is the number of allowances "freed-up" times the estimated price. Considering the lead time required and length of useful life for many compliance options, an unexpected change in the price of allowances could turn a cost-effective option to one that is not.

This leads to an important and difficult question concerning the implementation of the CAAA for utility regulators (and the third source of uncertainty, that is, state and federal regulatory treatment): how should this risk be allocated between ratepayers and the utility? In the past, when a scrubber was installed, for example, because of a federal or state mandate, the prudently incurred costs were simply passed through to ratepayers. Now, however, when a scrubber is completed at a cost of $600 a ton, to use the above example, but allowances sell for $500 each, should the utility be allowed to recover the full cost of the scrubber or only the cost of the best alternative? Who should be responsible for the sunk cost of the investment?

This is, of course, not the only source of possible forecast error during the compliance planning process. Other factors such as fuel prices, construction cost, load growth, and realized (as opposed to estimated) energy saving from DSM will affect the postinvestment prudence of a utility's compliance decisions.

Partly in reaction to the market and regulatory uncertainty, some have proposed that greater assurances be given to utilities than traditionally provided such as preapproval (discussed below).

Policy Choices: One overriding concern on risk allocation is that irrespective of who bears the risk, the party taking the risk should also receive any benefit or loss associated with the compliance decision. In other words, the risk and the reward or penalty should be symmetrical. If ratepayers are assuming all of the cost of a utility's compliance cost, then any gain that may result from the sale of allowances would flow back to them. If the investment in retrospect was more costly than some alternative and the decision was arrived at prudently by the utility, then the cost would still be on the ratepayers. If an incentive is provided to the utility that allows shareholders a portion of the benefits from a good decision, symmetry requires that they share in any downside losses that may occur as well.

Many public utility commissions deal with regulatory and market uncertainty within the context of integrated resource planning. In addition, commissions can develop clear guidelines that detail to utilities the regulatory treatment of allowances and compliance costs. These guidelines can be developed through a joint process between the commission and utilities. In the case of multistate utilities or holding companies, these discussions may include several commissions (including FERC) and their jurisdictional utilities. Several commissions are now developing rules and procedures through joint meetings and notices of inquiry. Another means of dealing with these uncertainties is through a form of prior approval or preapproval.

Issue: Integrated resource planning and compliance planning

Policy Questions: How does CAAA compliance planning fit into the integrated resource planning framework? How are other considerations of the IRP process, such as DSM and environmental externalities, affected by the addition of compliance planning?

Background: The CAAA requires compliance plans to be filed with the federal EPA in phase I and with either the state air quality agency (if certified by the federal EPA) or the federal EPA in phase II. Except when special provisions of the CAAA are intended to be used (such as phase I extension bonus allowances or the reduced utilization provision for phase I plants), the EPA will not require detailed compliance plans. To satisfy Title IV requirements, the utility will have to certify that it will have sufficient allowances for its operation. State regulated electric utilities, however, in many cases will be required to submit a detailed compliance plan to the state commission.

Many states now have an IRP-type process in place or are currently developing one. States vary in the level of involvement that the commission takes in this planning process and the level of detail the utility is required to submit. IRPs may contain provisions for providing the utility with an incentive or removing a disincentive to invest in DSM programs, provisions for environmental externalities, and competitive bidding for demand and supply resources. CAAA compliance planning, itself a complex task, will have to be integrated into and among these complicated considerations.

<u>Policy Choices</u>: There appears to be little debate that if a state has an IRP process or is currently developing one, compliance planning should be included in the process. Since the overall goal of IRP is to integrate the utility's available resources given the constraints to their use and to arrive at a least-cost solution given these constraints, if CAAA compliance is not included, the result will be something other than a least-cost solution.

There is less agreement on whether IRP should explicitly incorporate externalities and whether SO_2 should be considered an externality if environmental externalities are dealt with in the IRP (by one survey fifteen states do to some extent). One view is that the CAAA internalized SO_2 and NO_x environmental costs requiring no further consideration, but other pollutants, such as CO and CO_2, still may be treated in the IRP process. A contrasting view is that while the CAAA may have solved the national problem with these substances, local environmental costs may still exist.

Of particular concern is developing a plan that is flexible and able to make adjustments easily to changing conditions. An inflexible plan can commit a utility to certain actions even though conditions may have changed in such a way that a different course of action is warranted. Building flexibility into a plan is not a straightforward task. Trying to account for every possible contingency in advance can render a plan cumbersome and unworkable. Commissions can give their utilities more incentive to change a plan, when warranted, by allowing the recovery of costs committed to in a previous plan.

This kind of commitment by a commission has its down side, however, since it presumes that the commission has available the same level of information and resources to make a decision as the utility. This is related to the risk allocation problem in the sense that to the extent an agreement of a plan between the commission and a utility commits the commission to allow cost recovery (and assuming that the plan is implemented in a prudent manner) the commission cannot disallow costs because the plan that it agreed to was flawed. This is a fundamentally different allocation of risks than traditional regulation with retrospective review. The result is that ratepayers assume more risk than when such assurances are not made by a commission.

Issue: Prudence review of compliance decisions

Policy Questions: Are prudence reviews of compliance planning decisions appropriate? How can a prudence review be used to properly allocate the risks of compliance planning? What guidelines should be followed in applying the prudence test? How is the prudence test different from its alternative, preapproval? Is it preferable?

Background: Many contend that state commissions cannot engage in "business-as-usual" for compliance planning because the associated regulatory risks are too great for utilities to plan for and take appropriate actions to comply with the CAAA. In particular, some contend prudence reviews will result in the underutilization of allowance trading as a compliance option. They contend the use of a prudence test will result in utilities taking a "go-it-alone" attitude so that much of the potential gains from allowance trading will not be realized. Opponents of the prudence test contend acid rain compliance planning is not "business-as-usual" and utilities must be protected from regulatory risks to take part in the market. Proponents of the prudence test, on the other hand, contend that its use is not only compatible with compliance planning but necessary both to allocate risks between ratepayers and shareholders properly and provide the utility with an incentive to engage in least-cost compliance planning.

Policy Choices: One option for regulators to use is the prudence test on acid rain compliance, but only after clear regulatory guidelines about use of the test are set forth. At a minimum, regulatory guidelines for use of the prudence test should incorporate the guidelines set out in the NRRI report *The Prudent Investment Test in the 1980s*. These guidelines are that (1) there is a presumption of prudence, (2) there is a standard of care that is reasonable under the circumstances at the time the decision was made, (3) there is a proscription against hindsight (no Monday-morning quarterbacking), and (4) there is a retrospective, factual review.

The presumption of prudence basically states that every investment and expenditure is presumed to be the result of reasonable judgment unless the contrary is shown. In other words, there is a rebuttable presumption of prudence. Without affirmative evidence showing mismanagement, inefficiency, or bad faith an investment is presumed to be prudent. A commission is not required to review all utility decisions regardless of their number, importance, or outcome. While the final result or outcome of an investment or expenditure might overcome the presumption of prudence, it does not necessarily address the question of whether the investment or expenditure was reasonable at the time the decision was made.

Once the presumption of prudence has been rebutted, the utility has the burden of proving that the decision was prudent under a standard of reasonableness under the circumstances that were known or reasonably knowable at the time. Perfection is not required. However, the more risky and expensive a compliance option is, the higher the standard of care to compensate for the risk and added expense. The proscription against hindsight is a corollary. Decisions are not subject to "Monday-morning quarterbacking," but are judged in the light of the conditions and circumstances at the time of the decision, not the later final result or outcome.

The fourth guideline is that there be a retrospective, factual review to develop evidence of whether the decision made was reasonable given the facts and circumstances at the time the decision was made. Because the relevant period of time was when the decision was made, the review is necessarily retrospective. It is also factual. Care must be taken not to create anachronisms when determining the reasonableness of past decisions. For example, it would be improper to use facts and circumstances that were only known in the present to judge the reasonableness of decisions made in the past.

If the decision is to have a prudence review, then there is a policy question of whether to conduct the prudence review on the compliance decisions themselves or merely their implementation. Applying a prudence review to compliance decisions has the advantage of supplying the utility with an incentive to engage in the lowest cost planning, because the decisions would be subject to review. The utility would then have an ongoing responsibility to make certain that its compliance plan was up to date and that it took advantage of opportunities in the allowance trading market. Also, a prudence review would allow regulators to separate utility-specific idiosyncratic risks (controllable by the utility) that the utility should be held accountable for from the systematic industry-wide risks typically held to be beyond the utility's control. Thus, the regulator implicitly can take into account the ratepayer's beneficial interest in the utility pursuing the lowest cost compliance options, including the ratepayers' beneficial interest in the utility's allowances. The principal disadvantage of applying a prudence review to compliance planning is that the utility is still subject to regulatory risk. However, that regulatory risk is offset somewhat by clear guidelines on how the prudence test will be applied.

Others contend that if a state commission is involved in either integrated resource or least-cost planning with the acid rain compliance decision a part of the process, then a state commission is already involved in contemporaneously reviewing the compliance options and can at the time the decision is made decide whether it is reasonable. But a commission still should use prudence reviews to judge how well the utility implemented the compliance plans. In other words actions and expenditures to implement a commission-approved compliance plan would still be subject to a prudence review. The advantage of this approach is a lessening of regulatory risk, but the disadvantage is its tendency to "lock in" the utility to the commission-approved compliance plan. A utility might then have a tendency not to take advantage of market opportunities as they arose for fear that such aggressive moves might be held to be imprudent. Also, it may be more difficult to determine contemporaneously the reasonableness of a compliance plan and impossible to distinguish between risks that are idiosyncratic and those that are systematic. Once a plan is held to be reasonable, it would be difficult for a future commission to reverse a decision by an earlier commission that the compliance plan was reasonable, when such was not the case. An additional disadvantage is that the commission would need to judge the prudence of every decision in the compliance plan, which may strain commission resources. However, the incremental effort might not be so great if the commission staff together with the utility are already engaged in integrated resource or least cost planning.

Another option is not to engage in a prudence review at all, or to have a "contemporaneous" prudence review of both compliance plans and expenditures. Because a prudence review by definition is retrospective, such an approach is a form of preapproval and is discussed below.

In at least one state, Delaware, there is a court decision stating that the utility owes no fiduciary duty to its customer and the prudent investment test does not apply. Instead the relevant test is "abuse of discretion, bad faith, and waste." In such circumstances, it is best not to couch arguments in terms of the prudence test or fiduciary duties. Instead, one must look to one's statutory language and argue that the statutory terms "abuse of discretion, bad faith, and waste" imply fraud, abuse, or economic waste. An economic waste test might then be used to identify those idiosyncratic risks undertaken by the utility that went awry.

Issue: Preapproval of compliance plans

Policy Questions: What forms of preapproval are available for compliance planning and its associated expenditures? How does preapproval allocate the risk of compliance planning decisions? How does preapproval affect the utility's incentive to engage in efficient behavior to comply at the lowest cost to ratepayers? To the extent that preapproval might shift risks to ratepayers, should a commensurate adjustment to the rate of return on equity be made?

Background: There are two basic forms of preapproval. Preapproval of planned actions and preapproval of expenditures. In the context of acid rain compliance planning a preapproval of planned actions means that a state commission reviews a utility's compliance plan, which may be a part of a larger integrated resource or least-cost plan, agrees that the utility's compliance plan is reasonable, and agrees to support those expenditures prudently undertaken to complete the compliance plan. The only difference between preapproving planned actions and many other forms of approving investment plans that are already in place is that preapproving planned actions specifically finds that the utility's planning is prudent. There is little or no danger of hindsight, because there is a contemporaneous review of the compliance plans.

Another type of preapproval is a preapproval of expenditures, which refers to a state commission approving the recovery of expenditures without the traditional retrospective, factual inquiry into whether the expenditures were prudent or not. It is quite different from traditional commission practices as currently practiced at most state commissions. In the context of compliance planning implementation, a preapproval of expenditures would involve a contemporaneous prudence review (sometimes called a rolling prudence review) of expenditures in fulfillment of a commission-approved compliance plan. It would require close involvement by the commission or its staff and considerable resources to check the prudence of every possible expenditure. Otherwise, the staff or commission might become coopted by the utility because of the asymmetry of information available to the staff as opposed to that available to the utility. If the commission staff has the resources to check every utility expenditure for every conceivable error within the utility's control, then the danger exists that the commission staff will have taken over the utility's management task. Neither scenario is considered by many to be desirable.

Policy Choices: One choice is not to engage in any form of preapproval. The principal alternative to preapproval of planned actions and expenditures is a prudence review of both the compliance plans and expenditures to implement the plan. The major advantage of this approach, as noted above, is that it allows regulators to properly allocate idiosyncratic (controllable) risks to shareholders and systematic risks to ratepayers. It also creates an incentive for the utility to develop plans that are prudent so that they can withstand a retrospective, factual commission review. The prudence test also results in the utility taking reasonable steps to keep costs in line in implementing the compliance strategies in the plan.

Many contend that state commissions should engage in preapproval of planned actions, particularly if the commission approved the reasonableness of the utility's compliance planning as an integral part of the utility's integrated resource or least-cost plan. (Some state commissions require utilities to submit plans, but do not make any finding as to their reasonableness. Those states would probably not have preapproval of planned actions for compliance plans.) As noted above, this approach has the advantage of offering little or no opportunity of hindsight, thus lowering regulatory risk. While there might be a tendency for a utility to be reluctant to deviate from the commission-approved plan, the commission can require periodic updating of its compliance plan to reflect facts and circumstances as they change. This updating likely would be part of the state's integrated resource or least-cost planning process. Even so, there might be a tendency for the utility to ignore allowance trading opportunities unless sufficient flexibility were written into the plan so the utility realizes it is expected to take advantage of these opportunities. A prudence review is then available to assess how well the utility implemented the commission-approved plans. If periodic reviews and flexibility are built into the compliance plan, a preapproval of compliance plans might reduce regulatory risk with only minimal risk shifting of utility-controllable idiosyncratic risks from the shareholder to the ratepayer. Devising a commission-approved compliance plan that is flexible, subject to periodic review, and still has substance to it is, at the very least, challenging.

A few contend that preapproval of planned actions is not enough. To encourage utilities to comply with their statutory obligation at the lowest cost, they contend it is necessary to provide utilities with preapproval of compliance expenditures. The obvious advantage of this is that it reduces, if not totally eliminates, regulatory risk, thus lowering the utility's cost of capital. The disadvantages are numerous. In addition to the already mentioned danger that either the commission or its staff will become coopted by the utilities or the commission staff will take over the utility management's tasks, preapproval of expenditures involves a major shifting of utility-controllable idiosyncratic risks from shareholders to ratepayers. Unless there is a commensurate (major) lowering of the rate of return, this can result in the socialization of risks and the privatization of undue profits. But, even if the rate of return is lowered, a preapproval of expenditures in a cost-based regulatory scheme provides the utility with little incentive to minimize its costs. Retrospective reviews, such as prudence reviews, evolved to provide an incentive to the utility to minimize its costs in a cost-based regulatory environment. Merely lowering the utility's rate of return will not provide the utility with an incentive to minimize its costs.

B. Ratemaking Issues

* Compliance cost recovery mechanisms
* Incentives resulting from ratemaking treatment of allowances and compliance costs
* Valuation of allowances for ratemaking purposes

Issue: Compliance cost recovery mechanisms

Policy Questions: What regulatory mechanisms are currently available for recovery of compliance costs, such as pollution abatement equipment and allowance purchases? Are changes required to the current regulatory procedures used by commissions to deal with compliance costs and allowances?

Background: In general, pollution control equipment has received favorable rate treatment, that is, these investments in the past have usually been included in the rate base. The reason is that pollution control investments were a federal or state mandate. It is not clear, however, if this will continue given the discretion utilities now have to comply with the SO_2 requirements.

There are two different views as to whether significant changes are needed in the way commissions currently regulate utilities for implementation of the CAAA or if current regulatory mechanisms are adequate. One view is that allowances provide utilities and ratepayers an opportunity to significantly lower compliance costs than what would have occurred with command-and-control environmental regulation. There may be little incentive, however, to use the allowance market and minimize compliance costs with traditional ratemaking methods. Therefore, changes are required. A contrasting view is that current rules and procedures are sufficient, including sufficient incentives provided to control costs, to cope with compliance costs, allowances, and risk allocation. Moreover, there may be unintended negative consequences from too radical a change. Since considerable cost savings can be obtained, the argument goes, from trading allowances within an individual utility's system or power pool, state commissions should not be overly concerned with the development of the national allowance market. Others, of course, believe that this view is decidedly shortsighted and ignores the benefits of a national market.

<u>Policy Choices</u>: Under a traditional rate-base/rate-of-return regulatory approach, prudent investments in capital equipment, such as scrubbers and plant modification for fuel-switching, would be added to the rate base. Many states have construction work in progress (CWIP) provisions for pollution control investments that enable utilities to earn a return on their investments without having to file a rate case. This includes states that do not have CWIP for other types of capital investments. CWIP was designed to avoid the regulatory lag problem than can occur when there is a long interval between rate cases and the time it takes to settle a case after a filing. Also available is an allowance for funds used during construction (AFUDC) which would include the investment in rate base only after the facility was completed. After completion, a facility (if CWIP was not used) may be phased-into the utility's rate base rather that brought in all at once to avoid "rate shock." (For many larger utilities the investments will not be as large as some the nuclear projects that in the past have been phased-in.) Any revenue from the sale of allowances "freed-up" because of the investment may, under a traditional approach, be deducted from the asset value in the rate base.

Some compliance options require little or no capital investment, such as fuel switching or purchasing allowances. Again, under a traditional regulatory framework, the higher price for low-sulfur coal can be accounted for as an increase in operating cost in a rate case. Alternatively, these higher costs could be passed through an existing FAC. Since purchased allowances are a stream (rather than a stock) and are "used-up" along with the use of a fossil fuel or stored (banked) for future use, used allowances may be treated as an operating expense for ratemaking purposes. In a rate case, the number of allowances required for plant operation and the appropriate size of the allowance bank would be determined. This could be based on the operating needs of the utility and the availability of allowances. Commissions may consider guarding against unnecessary banking of allowances, particularly if allowance costs are allowed in rate base. There is an incentive to hold enough allowances since the statutory fine (in the CAAA) assessed against the company for not having sufficient allowances to cover emissions most likely would not be recoverable in rates.

An alternative to these and other traditional approaches are incentive-type mechanisms. By one recent survey, about thirty states now use some type of incentive mechanism for electric utility regulation. These mechanisms include incentives to achieve socially desirable goals, such as investment in DSM projects and incentives to minimize operating costs (thought to be insufficient with cost-plus regulation) such as power plant performance or benchmark standards. An incentive mechanism of the second type can be developed to minimize SO_2 control costs. While these types of mechanisms can be accomplished within a traditional regulatory structure, they do require some departure from cost-plus regulation.

An incentive mechanism for SO_2 control costs could set the benchmark at the utility's control cost, an estimated value of allowance, or, eventually when more market information is available, on the market price of allowances (based on a weighted average of short-term, long-term, and futures contracts, for example). If the utility is able to outperform the benchmark, it is allowed a share of the difference between the actual control cost and the benchmark. If the control cost is above the benchmark, the utility either recovers only the benchmark or some predetermined portion of the difference. Symmetry may require that the same proportion be used for a "gain" (the difference between the benchmark and control cost when the control cost is lower) as a "loss" (the difference between the benchmark and control cost when the control cost is higher). A primary advantage to adopting an incentive-based mechanism is that the utility would be rewarded for good performance (that is also in the interest of ratepayers) and penalize for bad decisions. This should increase the utility's motivation for adopting innovative and cost-effective approaches when developing a compliance strategy.

There is little doubt that current regulatory mechanisms can be used or modified to cope with the CAAA. There is a difference, however, between changes needed or required to get something done and changes that may be desirable because it is an improvement over the way things are currently done. A change from traditional to more incentive- or competitively-based regulation is intended as an evolutionary not revolutionary change. Also, commissions may regard the development of the allowance market as an important factor since considerable cost savings may still be achievable.

Commissions may consider that no matter which rate treatment is used, there are likely to be equity consequences. These are primarily from the assignment of control costs and the gains and losses from what turns out, perhaps years later, to be a good or a bad decision.

Issue: Incentives resulting from the ratemaking treatment of allowances and compliance costs

Policy Questions: What kind of incentives are provided to utilities with different regulatory treatments? What kind of incentives should utilities receive?

Background: Both a traditional and an incentive-based ratemaking approach will have an impact on the decision making process of a utility. Some have argued that if the commission commits to placing large capital expenditures in rate base, a utility's decision will be biased toward scrubbers, even though this may not be the lowest-cost option. Similarly, FACs may bias the utility toward a fuel-switching option. Counteracting any capital bias is the possible utility reluctance to invest in large capital projects because of past disallowances. This may result in the utility taking only short-term action (such as purchasing fuel) and foregoing a more capital-intensive (and more uncertain) option with long-term benefits to ratepayers.

The purpose of a CAAA compliance incentive mechanism is to provide an incentive to the utility to minimize its SO_2 control costs since, it is argued, there may be insufficient incentive, in some circumstances, with cost-plus regulation. A well structured incentive mechanism can avoid some of the problems associated with traditional approaches. If not structured properly, however, other unintended biases can occur.

Policy Choices: Commissions may be somewhat limited, statutorily, in the types of incentives they can provide to jurisdictional utilities. This may come about in three ways. First, if the utility is unable to meet the performance standard set by an incentive mechanism, it would then suffer a loss. However, some states require that all prudently incurred costs must be recoverable. Basing prudence on the market price may not be sufficient cause for what is in effect a disallowance. Second, if the utility outperforms the benchmark standard set by the commission, it could result in the utility earning more than its allowed rate of return. There may be a legal requirement (or temptation), therefore, to limit the gain thereby neutralizing any incentive. It may be difficult (and perhaps legally impossible) for a commission to provide assurances in advance to a utility that this would not occur.

Third, there may be state legislation that requires cost recovery of CAAA compliance costs, incentives to use in-state coal, or technology mandates. Several state legislatures, for example, have given assurances of cost recovery for continued use of local coal to preserve coal miners' jobs. These usually are political mandates decided with special interests in mind, sometimes independent of the cost to ratepayers. Placing a regulatory incentive mechanism on top of this type of mandate would simply be impractical since it would be unlikely that commissions would pass through the costs to ratepayers and then allow an incentive for the utility. If there was a gain from the mandated compliance action, it most likely would simply be passed-through to ratepayers.

It is important to consider that the allowance trading system itself is a national incentive mechanism. Developing a regulatory incentive system that dovetails with the national market may assist in the development of the market. This will not guarantee the expected saving will materialize, but may make it more likely.

Issue: Valuation of allowances for ratemaking purposes

Policy Questions: What value, for ratemaking purposes, should be used for the originally allocated allowances? How does the source of the allowances affect ratemaking? What kind of ratemaking treatment should the various types of bonus allowances receive?

Background: There are several types of allowances, but the vast majority are the originally allocated allowances from EPA. The phase I allocation is given in Table A of the CAAA and was based on a limit of 2.5 lbs. of SO_2/mmBtu for units larger than 100 MW. In phase II, these allowances will be given to existing units over 25 MW and some new units specified in the CAAA. The allocation will be based on a limit of 1.2 lbs. of SO_2/mmBtu for the average fuel consumption from 1985 through 1987 (unless granted a different base period by EPA). These originally allocated allowances are always associated with a particular unit (a unit is defined by the CAAA as a fossil fuel-fired combustion device that serves an electric generator). EPA has issued a Notice of Proposed Rulemaking with the phase II allowance allocations (published in the July 7, 1992 *Federal Register*).

Bonus allowances can be broken down into two general categories: (1) bonus allowances granted to reduce the burden of compliance, in effect a subsidy granted by the CAAA, and (2) bonus allowances that require some specific type of action by the utility. In the first category are the 200,000 allowances distributed to Illinois, Indiana, and Ohio in phase I. Examples of the second type of bonus allowances are the phase I extension allowances that require the utility to build a scrubber, and the conservation and renewable bonus allowances that require investment in a qualifying conservation program or renewable technology. Some additional allowances will be given for the use of certain types of fuels and to units already below the emission limit. However, the utility may not be required to make any changes in the operation of a qualifying facility to receive some of these bonus allowances. If modifications are required, then it falls into the second category of bonus allowances.

In addition, there are allowances that can be purchased from the EPA auction, directly from another source (utility, a nonutility industrial firm that has "opted-into" the system, broker, etc.), or transferred between affiliates of a utility. In these cases, some type of market value will be attached directly or implied. Finally, all allowances are issued for a particular year; they can then be used in that year or banked for future use.

Policy Choices: Commissions may consider the source of an allowance for ratemaking purposes. For example, the simplest case may be where allowances are purchased from a nonaffiliated source. In this case, the price paid for the allowances should, assuming a good faith effort by the utility, reflect a fair market price (also assuming the utility can or has justified the purchase as the lowest-cost solution). For ratemaking purposes, the value of allowances could be entered into an allowance inventory account and then treated as an operating expense (that is, allowance expense) when used. The difficulty, of course, is keeping track of the allowances and distinguishing them from the firm's other allowances. Commissions may consider using EPA's proposed serialization of allowances to track allowances for this purpose.

For bonus allowances that require an investment of some kind, the commission may associate the bonus allowances received with the investment made. Thus, allowances received for conservation investment could be deducted from the investment or expenses incurred. In general, commissions will be able to track both the cost incurred and the allowances received. It is less clear, however, if the deduction should be made upon receipt of the allowances or when used or sold. For bonus allowances that do not require an investment, the commission may treat them as a subsidy. Therefore, when these allowances are sold the revenue is deducted from the revenue requirement and if used is expensed at zero value. Commissions may consider for simplicity to have the utility "use up" these allowances first to prevent the utility from expensing purchased (that is, the most valuable) allowances first. A utility that does not take advantage of an opportunity to earn bonus allowances, when there is a benefit to doing so, may face a possible disallowance. Commissions should consider, however, that a utility is not guaranteed to receive the bonus allowances. Rather, commissions may look for a "good faith effort" by the utility to obtain them or a reasonable case being made that the utility would not qualify for the bonus.

Perhaps the most difficult problem for commissions is the originally allocated allowances. Their treatment is also perhaps the most important since this is the largest single type of allowances. The problem arises because the allowances are received at no cost from EPA but do have some market value. An original or historical cost basis would require that they be given a zero basis. A market or replacement cost standard would use the market price. The difference between the two methods in this case is more dramatic than the usual debate concerning, for example, valuation of power plants. In the case of other assets, the debate is between two positive values while with the original allowances it is between zero and a positive number. With power plants it is difficult to arrive at a market value since there is no "market" in a strict sense of the term; with allowances, however, there should eventually be one. Currently, however, there is insufficient market information (to date, there have been three publicly announced trades) to determine this value with any degree of confidence and there could be some time before a market develops that is able to provide reliable information. Using a market basis for ratemaking has the additional drawback that it could result in a significant profit or loss being incurred by the utility.

Nevertheless, despite its drawbacks commissions may still consider a market basis for the ratemaking treatment of the originally allocated allowances. There are two reason why it should be considered. First, it would explicitly recognize the value or opportunity cost of the asset held by the utility. Unlike bonus allowances, these allowances will be allocated each year to the firm. Also, they will be necessary for the operation of the utility and can be sold at some value. A second reason is that with increasing amounts of power being sold wholesale, it becomes more important for state commissions to properly account for the cost of producing power, including allowances. An original or historical cost basis would result in the power being undervalued and a subsidy being transferred from one group of ratepayers to another.

Unfortunately, there is no straightforward solution. A start may be to recognize the beneficiaries of the creation of the allowance system and the beneficial owners of the allowances (as opposed to title holder) based on the units receiving the allocation. One simple solution may be to reduce the value of the unit in rate base by the estimated value of the allowances. The problem is that the asset still has the same value as before (unit value plus allowances) and some units, particularly older phase I units, may already be mostly or completely depreciated. For utilities that have made some investment in pollution control equipment that resulted in the freeing-up of allowances, the revenue can be deducted from the asset value. The problem, as discussed above, is that this could result in an incentive to overcapitalize. Another solution may be to allow or require the utility to purchase the commission-determined ratepayer share of the allocation. A disadvantage with this is that for many utilities this would be a considerable investment. If feasible, however, it would then be viewed as other investments of the firm are for ratemaking purposes. This could, if deemed desirable, lead to a deregulation of the firm's compliance activities, once ratepayers have been compensated.

C. Jurisdictional Issues

* **Coordination among states--regional compliance solutions**
* **Allowances and multistate utilities and holding companies**
* **Wholesale power transactions and allowances**

Issue: Coordination among states--regional compliance solutions

Policy Questions: Would some form of regional coordination among states aimed at finding regional solutions to compliance be useful? If so, what form might it take?

Background: Many utilities face a problem that there will be several different agencies trying to answer the same questions related to acid rain compliance planning, emission allowance trading, and the ratemaking treatment of allowances and other options. To understand what forms of regional coordination might be useful, it is necessary to ask: (1) where might potential conflicts arise? (2) how can potential conflicts be avoided? and (3) how can state commissions as well as FERC come up with common solutions? In the case of a stand-alone utility, there is the potential for inconsistent regulation between state commissions if it serves more than one state in its service area. There is also the potential for jurisdictional conflict between FERC and the state commissions. The areas of potential conflict include conflicts about projections and assumptions necessary to reach least-cost solutions for compliance planning, and assumptions about implementing the least-cost solution. Forms of regional regulation should address these areas of potential conflict.

Policy Choices: One policy option for regional regulation is to begin by doing a utility-by-utility analysis of the potential coordination problems with state commissions. This would identify which state commissions could potentially reach inconsistent decisions on compliance planning and implementation. Then, one might urge state commissions that could reach inconsistent results to coordinate their compliance planning efforts on a formal or informal basis. There are several methods that could be used by state commissions to coordinate their compliance planning efforts. In states where there is statutory authority to do so, state commissions can hold joint trials or proceedings to determine on a formal basis their compliance plans for a multistate utility. However, it might be more useful if compliance planning for a multistate utility were undertaken in a more informal context such as a joint problem-solving workshop, involving all the state commissions regulating the multistate utility, the multistate utility itself, and all other interested parties. Such a forum might be more appropriate for compliance planning, which may be considered closely akin to integrated resource planning (IRP) and could lead to a coordinated approach. The objective would be to reach, at the very least, an informal agreement as to approach, and then to issue a generic policy statement to that effect.

Another option is for state commissions to act in tandem whenever possible. This could be accomplished through informal regional meetings of states that regulate a particular utility or group of utilities, or through the North American Electric Reliability Council's (NERC) or the National Association of Regulatory Utility Commissioners' (NARUC) regions that include common utilities, for example the New England Conference of Public Utilities Commissioners' (NECPUC) region for New England Power Pool (NEPOOL) utilities. State commissions might also act in tandem with the regulatory equivalent of model state laws, which would be adopted by each state commission in a region. Then state-by-state variations would be minor.

A concern is that regional regulation would only work if there is a high degree of coordination and cooperation between the states, and where appropriate, between states and FERC. Yet parochial state economic pressures are keenly felt by some state commissions and jurisdictional utilities sometimes encourage these potential conflicts by strategically gaming the state commissions by playing one against another. They can do this because of asymmetric flows of information. This suggests that the first step to any meaningful regional regulation is to develop a common data base on the subject utility and an ongoing dialogue between commission staffs.

Issue: Allowances and multistate utilities and holding companies

Policy Questions: Who has authority over allowances for multistate utilities and regional holding companies? If FERC has authority, is there a role for the state commissions to play? Might FERC abstain to exercise its jurisdiction in favor of the state commissions and, if so, under what conditions?

Background: Section 403(f) of the CAAA leaves federal and state jurisdictions unaffected by the emissions trading provisions of Title IV. The CAAA also provides that the PUHCA does not apply to the sale or acquisition of emission allowances. Instead, the CAAA maintains existing state commission and FERC jurisdiction for the oversight of utility compliance, as well as the ratemaking treatment of the allowances. Sections 205 and 206 of the Federal Power Act (FPA) gives FERC the authority to approve allocation and operating agreements of power pools, as well as amendments to those agreements. Once an agreement or an amendment to an existing agreement is filed with FERC it must act on that filing. Under section 205, it might be possible for regional holding companies, and perhaps centrally dispatched power pools, to shift from state to FERC jurisdiction for issues concerning the initial allocation of allowances within the regional holding company or centrally dispatch power pool where there are jointly owned units, the prudence of the regional holding company's or power pool's compliance plan (including issues related to preapproval), and the ratemaking treatment of allowances.

The possibility of federal preemption in regional holding company and centrally dispatched power pools was driven home in the United States Supreme Court case of Mississippi Power & Light Co., commonly referred to as the "Grand Gulf" case. In the Grand Gulf case, state public utility commissions were preempted from conducting a prudence review on a nuclear power plant that was subject to a FERC-approved cost-recovery allocation agreement. The FERC-approved allocation agreement was filed by a centrally dispatched regional holding company. State commissions are concerned that if they are preempted by FERC they will be precluded by the "filed tariff" doctrine from any meaningful role in deciding on the utility's acid rain compliance plan and the treatment of allowances.

Policy Choices: Some contend that our system of dual federalism has evolved from a system with bright-line jurisdictional boundaries to a more mixed system. Bright-line jurisdiction has distinct layers between the federal and state agencies. A more mixed system has state agencies implementing federal policies with the federal agencies reviewing the states' policy implementation for consistency with federal policy. In such a situation, there is a role for both FERC and the state commissions. One option is for FERC, to the extent possible, to avoid becoming immersed in CAAA implementation. Under this approach, FERC would work at "keeping its powder dry" by not rushing in to preempt the states. FERC would still need to act on occasion, such as the issuance of FERC's proposed Accounting Rule, but would not seek to preempt the states. For this approach to work, state commissions that regulate subsidiaries or members of a multistate regional holding company or power pool must strive to reach compliance planning decisions that are consistent or at least not inconsistent.

While state agencies are effective laboratories of regulation, it would be self-defeating for every state commission to implement compliance planning with a different, inconsistent approach. This option of state commissions striving to reach consistent decisions also has the advantage of allowing state commissions to engage in compliance planning, often within the context of least-cost or integrated resource planning, rather than FERC which has no authority or experience with IRP or compliance planning.

Even if FERC did exercise forbearance, it may not have complete control of its own destiny. If a utility makes a filing under FPA section 205, FERC may have no choice but to act on it. To avoid utilities from filing under FPA section 205, state commissions must consider regional cooperation for determining emission allowance policies and avoid issuing state policies that are meant to protect parochial state interests. State commissions have an interest in seeing that the national interest is served by the development of an efficient allowance trading market. Otherwise, FERC will find it difficult to resist taking a more active role. Perhaps the greatest danger is that state legislatures, in order to promote a parochial state economic interest, will limit the compliance planning options that utilities and the state commission can consider.

One option for avoiding FERC preemption for multistate regional holding companies or centrally dispatched power pools is to set up an ongoing dialogue between the state commissions that regulate the subsidiaries or members. It has been suggested (by several participants at the workshops and elsewhere) that state commissions conduct an early dialogue to develop regulatory guidelines that provide procedures for the review of compliance plans and review of the implementation of the compliance plans. With cooperation between the state commissions, serious disagreements on compliance plans might be avoided. Unless serious disagreement is avoided, federal preemption is possible.

Another possibility for avoiding FERC preemption is a more formal form of regional regulation. One such proposal, known as the Entergy-Arkansas Plan has been proposed in Congress. A formal regional regulation compact approach can then define the role of the various state commissions and FERC as to the allocation of allowances and the role of emission allowances in compliance planning for regional holding companies or centrally dispatched power pools. The disadvantage of this approach is that state commissions may lose some or all of their flexibility and ability to determine the form that regional regulation takes if Congress uses its compact power to require a particular form of regional regulation.

Another option for resolving issues that start out as state-state conflicts is for FERC to be brought in not as a decisionmaker but as a facilitator or referee for the conflict. FERC has authority to do so under section 209 of the FPA, which allows FERC to conduct joint boards, joint hearings, and joint conferences with the affected state commissions for matters that come under FERC jurisdiction. The use of a joint board might allow FERC to involve states in policy decisions back to the state commissions without violating the "nondelegation doctrine" that prohibits a federal agency from delegating its federal responsibilities to nonfederal agencies. This is so because the nondelegation doctrine does not apply to a joint board. Even though state commissions may be members of a joint board, the joint board itself remains a federal agency. No illegal delegation of federal authority takes place. FERC might use its role as a facilitator to help resolve inconsistent approaches to cost allocation and compliance strategies between state public utility commissions regulating different subsidiaries or members of regional holding companies or centrally dispatched power pools. If FERC is unsuccessful in facilitating an agreement between and among these state commissions, it may become necessary for FERC to reach its own decision and preempt the state public utility commissions. A disadvantage of joint boards as currently envisioned (by the FCC and FERC) is that the joint board's decision is only an initial decision with no more weight than that of a administrative law judge. It would be preferable if this practice were revised so that the practice becomes one where FERC defers to the decisions of the joint board.

Issue: Wholesale power transactions and allowances

Policy Questions: If FERC has authority over allowances connected with wholesale power transactions, is there a role for the state commissions? Will FERC abstain from exercising its jurisdiction, and, if so, under what conditions? Is there a role for a possible state-federal partnership?

Background: The FPA gives FERC jurisdiction over the treatment of allowances that are a part of a wholesale power transaction, particularly if the sale of the allowance was bundled as a part of the wholesale power transaction. Also, FPA section 203 provides FERC with authority to directly regulate sales of an asset, which conceivably might be used to regulate unbundled allowances. (Bundled allowances are allowances sold as part of a wholesale power transaction package. Unbundled allowances are sold separately from the wholesale power transaction.) State commissions are concerned that allowances connected with wholesale power transactions might be available at a lower cost through the allowance market than the allowances bundled in the wholesale power transaction.

Policy Choices: One policy option that has been suggested is that FERC only directly regulate bundled allowances that are a part of a wholesale power transaction. It is thought that unbundled allowances should not be regulated directly. An unbundled allowance would be bought or sold by the utility without any direct FERC regulation. However, the sale and purchase of the allowance might be subject to a prudence review if the ratepayers have an interest in the price of the allowance.

Another suggested option was that FERC might require at the wholesale level that all allowances be unbundled. While wholesale transactions might still involve a transfer of allowances, the implicit allowance price must be clearly and explicitly stated. Such a policy would make the allowance market more liquid, with greater price transparency. It would have the desirable effect of preventing the utilities from tying emission allowances with the purchase of wholesale power which, if allowed, could effectively close many independent power producers (IPPs) out of the wholesale power market. Further, it would allow FERC the opportunity to avoid a complex and cumbersome issue; that is, how to determine the cost of allowances in the context of market-based rates. The associated issues concerning market power in the allowance market would compound FERC's already difficult task of conducting market power inquiries on the transmission and generation when considering market-based rates for wholesale power transactions. Also, unbundling would avoid the problems associated with trying to unscramble the allowance transaction from the wholesale transaction. It would also make it easier and cleaner to deal with the question of whether the buyer and seller acted prudently. Under this option, FERC would want to require unbundling, but would preserve its authority to preempt state commissions from inappropriate state actions that are inconsistent with an efficient national emissions allowance market. (EPA's proposed Acid Rain Permits rule would also preempt state air quality agencies from taking actions that restrict allowance trading.) This unbundling might also be helpful for identifying transfers between holding company affiliates.