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REGULATORY POLICY ISSUES AND THE CLEAN AIR ACT: ISSUES AND PAPERS FROM THE STATE IMPLEMENTATION WORKSHOPS

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I. INTRODUCTION

I. INTRODUCTION

The National Regulatory Research Institute (NRRI), with funding from the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE), conducted four regional workshops[1] on state public utility commission implementation of the Clean Air Act Amendments of 1990 (CAAA). The workshops had four objectives: (1) to discuss key issues and concerns on CAAA implementation, (2) to encourage a discussion among states on issues of common interests, (3) to attempt to reach consensus, where possible, on key issues, and (4) to provide the workshop participants with information and materials to assist in developing state rules, orders, and procedures. From the federal perspective, a primary goal was to ensure that workshop participants return to their states with a comprehensive background and understanding of how state commission actions may affect implementation of the CAAA and to be able to provide guidance to their jurisdictional utilities. It was hoped that 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 involved presentations on specific issues by invited speakers. "Primary participants" from each state and other workshop attendees then discussed the issues raised by the speakers, as well as 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 containing information from NRRI regarding CAAA implementation and speakers' papers or outlines.[2]

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[1] The workshops were held in Charlotte, North Carolina for southern and eastern states in April 1992; St. Louis, Missouri for midwestern states in May 1992; Portsmouth, New Hampshire for New England states in January 1993; and Albuquerque, New Mexico for western states in March 1993.

[2] These workbooks are available upon request from NRRI. This report contains many of the speakers' papers.

An unresolved question that ran throughout the workshops was the uncertainty surrounding the development of the allowance market. Questions for state commissions include the following: What is the role state commissions and FERC should 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, most questions concerning the regulatory treatment of compliance costs and allowances returned to the market development questions.

The debate on the market's development has shifted during the one-year period that the workshops took place. During the first two workshops, the concern was whether the market would develop and what should (or should not) be done if it does not develop or what should be done to foster it. By the time of the last two workshops were held, there had been several trades and considerable interest in the EPA auction (which took place on March 29, 1993). As a result, the concerns focused the question on what will be the characteristics of the nascent market and its future, including prices and the role of the various market facilitators that have since emerged.

This report is divided into two main sections. In Section II, eleven principal issues are identified and discussed. These issues were chosen because they were either the most frequently discussed or they were related to the questions asked in response to the speakers' presentations. This section does not cover all the issues relevant to state implementation nor all the issues discussed at the workshops;[3] rather, Section II is intended to provide an overview of the planning, ratemaking, and multistate issues. Part III is a series of workshop papers presented by some of the speakers and is organized by workshop session.

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[3] For an overview of the Title IV provisions of the CAAA and a more complete discussion of these and other issues see, Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, May 1992).

II. REGULATORY POLICY ISSUES

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
- Confidentiality and Proprietary Information

Issue: Allocation of Risks, Rewards, 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 concerning the uncertainty surrounding a utility's 1990 Clean Air Act Amendements (CAAA) compliance decisions. There are three 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 the uncertainty of fuel prices; (2) technological uncertainty that arises from technological change, which 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, regardless of CAAA compliance planning.

The first and second types of uncertainty, in the context of the CAAA, stem from the flexibility in the allowance system.[1]

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[1] This flexibility was not present under command-and-control environmental regulation. Utilities now have a wide variety of compliance options from which to choose.

However, the compliance decision made by a utility is highly dependent on the price of allowances. For example, examining several options on a dollars-per-ton of sulfur dioxide (SO_2) removed (not, of course, the only criteria used to choose an option), the choices may look like: (1) build a scrubber priced at $600 a ton, (2) switch to low-sulfur coal priced at $450 a ton, (3) invest in a clean coal technology priced at $800 a ton, or (4) purchase allowances priced at $500. If a choice were made simply on this basis, then the switching option would be chosen.

However, 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, or 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 the length of the useful life for many compliance options, an unexpected change in the price of allowances could turn a cost-effective option into one that is not.

This leads to an important and difficult question concerning the implementation of the CAAA for utility regulators:[2] How should this risk be allocated between ratepayers and the utility? In the past, when a scrubber was installed, 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

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[2] This is the third source of uncertainty, that is, state and federal regulatory treatment.

of $600 a ton but allowances sell for $500 each, the question arises: 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 not the only source of possible forecast error during the compliance planning process. Other factors such as fuel prices, construction costs, load growth, and realized (as opposed to estimated) energy savings from demand-side management (DSM) will affect the postinvestment prudence of a utility's compliance decisions.

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

<u>Policy Choices</u>: 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 borne by 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.

Many public utility commissions deal with regulatory and market uncertainty within the context of integrated resource planning (IRP). 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. A number of 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: IRP and Compliance Planning.

Policy Questions: How does CAAA compliance planning fit into the IRP 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,[3] 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. However, state regulated electric utilities 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 will have to be integrated into and among these complicated considerations.

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[3] For example, the use of phase I extension bonus allowances or the reduced utilization provision for phase I plants.

Policy Choices: There appears to be little debate that compliance planning should be included in the IRP process. Since the overall goal of IRP is to integrate the utility's available resources and to arrive at a least-cost solution, the result will be something other than a least-cost solution if CAAA compliance is not included.

There is less agreement regarding whether IRP should explicitly incorporate externalities and whether SO_2 should be considered an externality, if environmental externalities are dealt with in the IRP process.[4] One view is that the CAAA internalize SO_2 and nitrous oxide (NO_x) environmental costs requiring no further consideration, but other pollutants, such as carbon monoxide (CO) and carbon dioxide (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.

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[4] By one survey, fifteen states deal with environmental externalities in the IRP process to some extent.

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 to the extent that an agreement on a plan between the commission and a utility commits the commission to allow cost recovery (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 given 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 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 to 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. This option should be used 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*.[5] 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, 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. Although 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 pertaining to 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 needs to be in order to compensate for the risk and added expense. The proscription against hindsight is a corollary. Decisions are not subject to

[5] Robert E. Burns et al., *The Prudent Investment Test in the 1980s* (Columbus, OH: The National Regulatory Research Institute, 1984).

"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 must 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 on 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 and the acid rain compliance decision is 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 determine whether it is reasonable. However, 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. However, 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 it might be 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. 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 were 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 customers 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. Rather, 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 and contemporary commission practices. 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 to be desirable.

<u>Policy Choices</u>: 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.[6] As noted above, this approach has the advantage of offering little or no opportunity of hindsight and lowering regulatory risk. Although 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 the utility's compliance plan to reflect facts and circumstances as they change. This updating would probably 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 was written into the plan. A prudence review would then be available to assess how well the utility implemented the commission-approved plan. 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

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[6] 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.

numerous. In addition to the already mentioned danger that either the commission or its staff will become coopted by the utility 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. However, 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.

Issue: Confidentiality and Proprietary Information.

Policy Questions: Why are issues of confidentiality likely to be raised in the context of acid rain compliance planning and emission allowance trading? What are the special concerns raised by confidentiality requests and claims of proprietary information? What are the state commission policy options for dealing with confidentiality and proprietary information in the context of compliance planning and allowance trading?

Background: Requests for confidentiality based on claims of proprietary information are being raised by utilities in the context of acid rain compliance planning and emission allowance trading. However, these issues are not unique to compliance planning or allowance trading. State commissions have heard these requests before in similar contexts; namely, in circumstances when issues raised because of new competitive forces are introduced in the context of an evidentiary-type setting. For example, requests for confidentiality and claims of proprietary information have been raised in the context of licenses and entry in telecommunication services. There, the concern is that existing or potential competitors could use the regulatory process to increase their competitor's costs, to cause delays in entry, or to engage other anticompetitive behavior by acting as a price follower or copying innovations or new service offerings. Similar claims of proprietary information and the need for confidentiality have been raised in fuel and purchased gas adjustment hearings, and in the solicitation and evaluation of competitive bidding for new power sources. In each of these circumstances, the legitimate concern of the utility is the potential for anticompetitive use of the evidentiary hearing process. On the other hand, the commission and its staff must be concerned with whether its hearing fulfills the requirements of any applicable open meeting or sunshine laws. They must also be concerned about due process, which in this case concerns the ability of staff, consumer advocates, and other intervenors to cross-examine and rebut confidential evidence and proprietary information. Finally, commissioners and staff must also be concerned about substantive due process. Their decision must be based on substantial evidence found within the four-corners of the record. The issue then, raised by evidence subject to confidentiality, is whether there is an adequate record upon which to base a decision or to judge an appeal.

Policy Choices: There are a number of policy options for state commissions faced with requests for confidentiality and claims of proprietary information. First, commissions and staff can limit the occasions for potential misuse of market-sensitive information by limiting the use of burdensome discovery requests, including fishing expeditions for irrelevant and immaterial inquiries. This requires administrative law judges or sitting commissioners to be cognizant of the potential anticompetitive misuse of information. One solution is for the sitting commissioners or administrative law judges to provide for examination of market-sensitive information by attorneys of the parties under protective order or under seal with no disclosure to competitors, potential competitors, or the press. If done, then cross-examination and live testimony would be in a "cleared room." Outside expert witnesses would be given access to the information but would be bound by the protective order. In testimony and orders, references to designated evidence would be by citation and not by quotation. Finally, the evidence under protective order would be delivered to a reviewing court under seal. A protective order might be appropriate when dealing with (1) materials or documents related to specific customers, (2) employee-sensitive information, (3) reports or work papers that comprise the work product for a case, (4) marketing analyses or other market-sensitive information, (5) strategies employed, to be employed, or under consideration for contract negotiations, (6) trade secrets, and (7) other similar confidential and private technical, financial, and business information. The latter four are particularly relevant to acid rain compliance and emission allowance trading. However, before a commission takes the step of placing evidence under a protective order, it must balance what is good for the market with the public interest served in open hearings. When considering a request for a protective order, the burden of persuasion is on the party requesting the order.

RATEMAKING ISSUES

- Compliance Cost-Recovery Mechanisms
- Incentives Resulting From the 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? Should commissions change current regulatory procedures 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, and 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, 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.

Policy Choices: 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 which would include the investment in rate base only after the facility was completed. After completion, a facility may be phased into the utility's rate base (if CWIP was not used) rather that brought in all at once to avoid "rate shock." (For many larger utilities the investments will not be as large as some of 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 incurred 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 fuel adjustment clause (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 sufficient allowances since the statutory fine (in the CAAA) assessed against the company for not having enough allowances to cover emissions most likely would not be recoverable in rates.

An alternative to these and other traditional approaches is 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 penalized 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 they are 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 should 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 decisionmaking 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 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 occur 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 political mandates usually are decided with particular constituencies 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 savings 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, however, 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 pounds of SO_2 per million British thermal units (mmBtus) for units larger than 100 megawatts (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 pounds of SO_2 per 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 its final phase II allowance allocations Rulemaking.[7]

Bonus allowances can be broken down into the following 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.

[7] U.S. Environmental Protection Agency, 40 CFR part 73, Acid Rain Program, *Federal Register* (March 23, 1992).

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 in order 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 (a utility, a nonutility industrial firm that has "opted into" the system, a broker, and so on), 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 having 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 the debate 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 is a market developing currently. Unfortunately, at the moment there is insufficient market information[8] to determine this value with any degree of confidence and it 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 want to consider a market basis for the ratemaking treatment of the originally allocated allowances. There are two reasons why this 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

[8] To date, there have been several publicly announced trades and one EPA auction of allowances (conducted by the Chicago Board of Trade).

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 starting point may be to recognize the beneficiaries of the creation of the allowance system and the beneficial owners of the allowances (as opposed to the title holder) based on the units receiving the allocation.[9] 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. However, if feasible, it would then be viewed as other investments of the firm are viewed for ratemaking purposes. Once ratepayers have been compensated, this could lead to deregulation of the firm's compliance activities.

[9] Rose et al., *Public Utility Commission Implementation*, Chapter 8.

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 the 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 the following questions: (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, which involved 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 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 or the National Association of Regulatory Utility Commissioners' regions that include common utilities, for example the New England Conference of Public Utilities Commissioners' region for New England Power Pool 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 from exercising 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 Public Utility Holding Company Act of 1935 (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: (1) the initial allocation of allowances within the regional holding company or centrally dispatched power pool where there are jointly owned units, (2) the prudence of the regional holding company's or power pool's compliance plan (including issues related to preapproval), and (3) the ratemaking treatment of allowances.

The possibility of federal preemption in regional holding company and centrally dispatched power pools was driven home in the U.S. Supreme Court case of Mississippi Power & Light Co., commonly referred to as the "Grand Gulf" case.[10] 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 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

[10] Mississippi Power & Light Co. v Mississippi, 487 U.S. 354 (1988).

reach compliance planning decisions that are consistent or at least not inconsistent.

Although 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 integrated resource or least-cost 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 should consider regional cooperation for determining emission allowance policies and avoid issuing state policies that are meant to protect parochial state interests. State commissions should consider that they have a responsibility to see 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 from state legislatures that promote parochial state economic interests by limiting 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 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 type 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 begin 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 Federal Communications Commission and FERC) is that the joint board's decision is only an initial decision with no more weight than that of an 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 the sale of an asset, which conceivably might be used to regulate unbundled allowances.[11] 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

[11] Bundled allowances are allowances sold as part of a wholesale power transaction package. Unbundled allowances are sold separately from the wholesale power transaction.

prudence review if the ratepayers have an interest in the price of the allowance.

Another suggested option is that FERC might require at the wholesale level that all allowances be unbundled. Although 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 out of the wholesale power market. Further, it would allow FERC the opportunity to avoid a complex and cumbersome issue: 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 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.[12]

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[12] EPA's Acid Rain Permits rule (40 CFR part 72; § 72.72) would also preempt state air quality agencies from taking actions that restrict allowance trading.

This unbundling might also be helpful to prevent one group of ratepayers, either inadvertently or deliberately, from subsidizing another. Unbundling would explicitly identify the number and value of allowances transferred between holding company affiliates or between nonaffiliated companies. Subsidizing could be done deliberately, in a competitive situation, to gain an advantage over competitors who have a lower allocation of allowances or fewer allowances in reserve. Inadvertent subsidization could occur when regulators are not tracking the source of allowances used by a company involved in a wholesale power transfer. Regulators can arrange for the compensation of the source of allowances in an unbundled transaction or where the terms of the allowance transfer are specifically provided for in a contract separate from the power being transferred.

III. SPEAKERS' PAPERS

Session I

The Role of Public Utility Commissions and Other State Agencies in Implementing the Clean Air Act Amendments of 1990

- Acid Rain Compliance: The Need for Regulatory Guidance, Barry D. Solomon

ACID RAIN COMPLIANCE:
THE NEED FOR REGULATORY GUIDANCE

by

Barry D. Solomon[1]

Why Is Guidance Needed?

The Clean Air Act Amendments of 1990 (CAAA) and the Acid Rain Program provide a stark contrast to traditional air pollution regulation.[2] The command-and-control policy is seen as too expensive for sulfur dioxide (SO_2) control, and more flexible compliance, including an emphasis on energy efficiency and SO_2 emission allowance trading, is encouraged by this landmark law. The CAAA also mandates reductions in nitrous oxide (NO_x) emissions from electric power plants. These emissions will be controlled in the traditional technology-based manner, though Title IV of the CAAA provides modest flexibility by allowing some utility units to average their NO_x emission rates.[3]

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[2] See Public Law 101-549, Title IV, November 15, 1990.

[3] U.S. Environmental Protection Agency, Proposed Acid Rain Nitrogen Oxides Emission Reduction Rule (40 CFR Part 76). It is recognized that in order to meet the National Ambient Air Quality Standards for urban ozone under Title I of the CAAA, several agencies, including California's South Coast Air Quality Management District and the Texas Air Control Board, and the Northeast States for Coordinated Air Use Management (NESCAUM), are considering NO_x offsets and trading.

Since emission allowances are a new and unique commodity with no exact model or precedent, state public utility commissions need to provide guidance to electric utilities in order to minimize regulatory uncertainty about rate and accounting treatment of allowances (and accompanying risk aversion on the part of utilities), and acceptable acid rain compliance options or plans.[4] The novelty of the allowance trading system makes it likely that some changes in regulatory procedures and decisions will have to be made. Guidance is needed from commissions instead of from the EPA because section 403(f) of the CAAA preserves state and Federal Energy Regulatory Commission (FERC) jurisdiction over electric utility regulation. Moreover, the commissions are in the best position to determine what are the best compliance plans for their own investor-owned utilities. If this guidance is not issued, the large cost savings expected under the Acid Rain Program, as compared with command-and-control regulation, may not be realized.

Even in the West, where all of the major fossil-fueled power plant units are "phase II" affected units (which do not need to comply with the Acid Rain Program until the year 2000),[5] it is important to issue guidance and to plan for compliance early. This is because the CAAA has created an incentive program for the early use of conservation and renewable energy generation that may require regulatory reform, and emission allowances may be available in the early years for purchase at discount prices. States such as California, Washington, and Oregon, with aggressive energy conservation and renewable energy programs, are ahead of the game. The Western States region is very large and diverse, and as is the case with externalities such as carbon dioxide, how one

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[4] See B. D. Solomon and K. Rose, "Making a Market for SO_2 Emissions Trading," *The Electricity Journal*, 5, no. 6 (July 1992): 58-66. Another area of former uncertainty, the income tax treatment of allowances, has been addressed by the Internal Revenue Service, "Revenue Procedure 92-91, Regarding Income Tax Consequences of Air Emission Allowance Program Established by Clean Air Act Amendments of 1990," *Internal Revenue Bulletin 1992-46* (November 16, 1992).

[5] U.S. Environmental Protection Agency, 40 CFR Part 73, Acid Rain Program, *Federal Register*, March 23, 1993.

state addresses acid rain control and energy conservation will affect other states in the region since interstate power sales are very commonplace.

Fortunately, a good basis or model for developing guidance exists or will soon exist on all the relevant issues. This paper will briefly discuss recent efforts to develop guidance on the rate and accounting treatment of allowances. In addition, the paper will cover several innovative aspects of the Acid Rain Program that may require state regulatory action. These areas include linking acid rain compliance planning to the integrated resource planning (IRP) process, and using allowance trading and energy efficiency to reduce the costs of acid rain compliance.

What Kind of Guidance?

Rate and Accounting Treatment of Allowances

The rate treatment of allowances has been addressed and debated in a variety of forums, such as the Keystone Center Dialogue on State Regulation of Allowance Trading and in Commission dockets in Ohio, Pennsylvania, New York, and Georgia. The major publications on this subject include a 1992 article by Solomon and Rose,[6] and more importantly, NRRI's May 1992 seminal report on state commission implementation of the Acid Rain Program.[7] That report focused on the benefits of incentive ratemaking procedures to encourage utilities to engage in allowance trading, while also addressing the more fundamental topic of cost recovery options for allowances and acid rain compliance expenditures.

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[6] Note 4, op. cit.

[7] Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992).

The Ohio and Pennsylvania commissions have released orders on allowance trading and ratemaking issues.[8] The benefit of issuing ratemaking guidance for allowances is more in eliminating regulatory uncertainty than in any inherent advantage of a particular ratemaking approach. However, the author shares the NRRI report's view that incentive ratemaking to encourage allowance trading should be considered by the states.

The accounting treatment of allowances is less important than their rate treatment, and should be addressed after the appropriate ratemaking procedure is resolved by rate regulators. FERC, however, has done a great service by issuing their Rulemaking on Revisions of the Uniform System of Accounts (USOA) for Allowances in 1993.[9] These revisions establish uniform accounting requirements for allowances and would add new balance sheet and income statement accounts to the USOA to record the acquisition, holding, and disposition of allowances. Additionally, the rule includes requirements for the valuation and reporting of allowances and related transactions. State commissions should consider adopting the same accounting procedures.

Acid Rain Compliance Planning

The formal acid rain compliance plan requirements are detailed in EPA's Acid Rain Permits rule that was promulgated on January 11, 1993,[10] and are streamlined as compared with past air pollution permit requirements. In phase I, EPA is the permitting

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[8] See, Public Utilities Commission of Ohio, "In the Matter of the Commission's Investigation into the Trading and Usage of, and the Accounting Treatment for, Emissions Allowances by Electric Utilities in Ohio," Case No. 91-2155-EL-COI, January 20, 1993; Pennsylvania Public Utility Commission, "Policy Statement on Clean Air Act Emission Allowances," 52 Pa. Code Sections 69.291-69.294, January 21, 1993.

[9] Federal Energy Regulatory Commission, Docket RM92-1, Order 552, "Revision of Uniform System of Accounts for Allowances under the Clean Air Act Amendments of 1990," March 26, 1993.

[10] 40 CFR Part 72.

authority, and in phase II the state air agency will generally issue the acid rain permits. State commissions may well find it useful to require and review more detailed acid rain compliance plans of affected utilities. Guidance on plan development and implementation by the commissions in coordination with the state air agencies would be very helpful and in the best interest of least-cost compliance.

Good acid rain compliance planning should have many of the same features of, and should be integrated with, IRP. Mitchell's comprehensive 1992 survey of state IRP programs found that many of the western states have good IRP, with California, Nevada, Oregon, and Washington leading the way.[11] Hirst has provided some valuable suggestions about how to integrate acid rain compliance planning with IRP,[12] and Brick has suggested useful guidelines for regulators to follow in reviewing the plans.[13]

It is instructive to review some guidelines for a good acid rain compliance plan:

- The plan should be systemwide and comprehensive.
- The plan should be transparent with clearly documented assumptions.
- The plan should consider a reasonably large number of assumptions and compliance options (for example, fuel prices, scrubbing and allowance trading costs, risk and uncertainty).
- The plan should consider the potential for energy efficiency in a least-cost compliance strategy.[14]

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[11] C. Mitchell, "Integrated Resource Planning Survey: Where the States Stand," *The Electricity Journal*, 5, no. 4 (May 1992): 10-15.

[12] E. Hirst, "Data and Analysis Needed to Prepare an Electric-Utility Integrated Resource Plan," presented at the NRRI 1992 Clean Air Workshop in St. Louis, Missouri, May 7, 1992.

[13] S. Brick, "Analysis of Utility Acid Rain Compliance Plans: A Discussion of Issues and Methods," presented at the NRRI 1992 Clean Air Workshop in St. Louis, Missouri, May 7, 1992 (reprinted in the next section of this volume).

[14] For example, EPA's Conservation and Renewable Energy Reserve (CRER) allowances, reduced utilization of phase I units, and systemwide emissions reduction through conservation after compliance deadlines.

Allowance Trading and Energy Efficiency

Allowance trading and energy efficiency deserve particular attention from regulators in an IRP process, because they are newer and less familiar options for compliance. A good IRP process is generally well suited to accommodate allowance trading and should consider all aspects, that is, purchase, sale, generation (through overcontrol of high SO_2-emitting units), and banking of allowances. Although only a handful of allowance trades have so far been announced by utilities, the expected price of emission allowances continues to be low, underscoring the need for utilities and regulators to seriously consider purchasing allowances in compliance strategies. The Chicago Board of Trade held the first of a series of annual auctions for EPA of advance and spot allowances on March 29, 1993, with some of the key results such as the allowance prices made public. Everybody is encouraged to participate in these auctions. A particularly expensive acid rain compliance plan that does not consider allowance trading may trigger a review by a commission, or at least revision to an IRP.

States that are leaders in utility energy conservation programs should be positioned to receive a significant number of allowances from EPA's CRER program. The CRER is a limited pool of 300,000 one-time allowances available to qualified utilities, beginning on July 1, 1993.[15] Although there are numerous criteria to qualify for this reserve, the most important ones are that:

- A utility must own or be the partial owner of at least one affected unit.
- A utility applying to the CRER must use qualified demand-side energy conservation or renewable-energy generation measures that were installed on or after January 1, 1992.
- A utility must have a least-cost plan or planning process for meeting future electric needs, which may consider social and environmental externalities.
- Investor-owned utilities must be subject to a ratemaking process intended to ensure net income neutrality (in order to be certified by DOE beginning in early 1993).

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[15] 40 CFR Part 73, Subpart F.

- In the case of qualified energy conservation measures, the energy savings must be verified after they occur, either by the state commission (if the commission uses periodic evaluation of energy savings to determine performance-based rate adjustments for energy conservation programs) or by EPA.

The six-month lag between the Net Income Neutrality reviews by DOE and the opening date for applications to the CRER was also established by EPA to send a signal to utilities, commissions, and others that it believes in rigorous verification of energy conservation savings claims, which require more than a minimal amount of time to accomplish. To implement this policy, EPA has developed *Conservation Verification Protocols*,[16] which may be used by utilities and commissions to guide them in their evaluation programs. EPA's *Conservation Verification Protocols* have three goals:

1. Conservation Verification Protocols should be strongly oriented toward measurement of energy savings, rather than engineering estimates.
2. Conservation Verification Protocols must be flexible since energy conservation is a very diverse activity.
3. Verification of energy savings should be cost effective and should require a level of data and analysis appropriate for specific measures and programs.

The author's advice to states and their utilities who would like to apply to the CRER is to review EPA acid rain rules and criteria, and to quickly determine where, if anywhere, their ratemaking and planning procedures may need to be strengthened in order to permit their utilities to qualify. For example, while DOE will determine which utilities meet the Net Income Neutrality requirement, in the West it is clear that California and Washington's current conservation incentives programs based on decoupling and shared savings are among the most comprehensive in the nation; Oregon and Colorado should soon follow suit. States that are uncertain about their compliance

[16] U.S. Environmental Protection Agency, *Conservation Verification Protocols*, EPA 430/8/B-92-002 (Washington, D.C.: U.S. Environmental Protection Agency, March 1993).

with the Net Income Neutrality provision might consult with DOE to ensure that an acceptable program can be put into place before the reserve is depleted.

The most widespread application of energy conservation to SO_2 emissions reduction comes from a simple principle inherent in the nationwide emissions cap of 8.95 million tons set by the CAAA: generating less electricity leads to systemwide reductions in emissions. Unlike the CRER program, credit for allowances freed-up through systemwide conservation is automatic after the year 2000; EPA will not require verification or other documentation of emissions reductions or energy savings from conservation programs. To the extent that conservation reduces generation at SO_2-emitting plants, a utility will simply have less monitored emissions and will be required to "retire" fewer allowances to cover its emissions.

The number of allowances saved by avoiding emissions systemwide may be greater than the number of allowances earned from the CRER. The number of allowances saved in this manner will be based on the actual emissions avoided; in contrast, under the CRER program the number of allowances earned will be based on an assumed SO_2 emissions rate of a clean coal plant at 0.4 pounds per million British thermal units (mmBtu). The magnitude of systemwide emissions reductions for a given utility will depend on several factors, including the emissions rates of different generating units in the utility's system and power pool, the production costs and dispatch order of different units, and the types of conservation measures adopted by the utility. The avoided systemwide emissions are likely to be the largest in phase II of the Acid Rain Program, when virtually all fossil-fuel units will be subject to stringent SO_2 emission limits.

Session II

Developing a Compliance Strategy

- Analysis of Utility Acid Rain Compliance Plans: A Discussion of Issues and Methods, Stephen Brick

- The Role of Integrated Resource Planning, Environmental Externalities, and Anticipation of Future Regulation in Compliance Planning Under the Clean Air Act Amendments of 1990, Stephen Bernow, Bruce Biewald, and Kristin Wulfsberg

ANALYSIS OF UTILITY ACID RAIN COMPLIANCE PLANS:
A DISCUSSION OF ISSUES AND METHODS

by

Stephen Brick[1]

Introduction

Utility acid rain compliance plans have begun to roll into public utility commissions around the eastern half of the country. These plans typically represent the combined effort of utility staff and consultants, and have evolved since early drafts of Title IV of the Clean Air Act Amendments of 1990 (CAAA) began to circulate, several years back. The filings themselves often consist of many volumes of technical analysis, supporting documentation, and accompanying testimony. Hundreds of computer simulations are often presented and these, in turn, are underlain by hundreds of assumptions covering a staggering range of variables. Commissions usually have little time and few external resources with which to review and in some cases, preapprove proposed utility actions. These requirements, particularly in times of limited staff and increasing workload, may seem overwhelming. So much so, in fact, that there may be a tendency among commissions to forego a comprehensive review, approve utility plans as filed, and hope for the best. There are at least three important reasons, however, why this should not occur:

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[1] Stephen Brick is Vice President of MSB Energy Associates, Inc. in Middleton, Wisconsin. The views and opinions of the author do not necessarily state or reflect the views, opinions, or policies of The National Regulatory Research Institute (NRRI), the U.S. Environmental Protection Agency (EPA), the U.S. Department of Energy (DOE), the National Association of Regulatory Utility Commissioners (NARUC), or its funding commissions.

(1) The magnitude of planned CAAA expenditures is large.

Proposed expenditures frequently equal or exceed those experienced when the last round of baseload generating capacity was added. In some cases, utility revenues will need to be increased by more than 10 percent to cover CAAA costs. These expenditures affect other aspects of utility planning and regulation, including ongoing integrated resource planning (IRP), buyback rates, power purchases and sales, and the cost of service to a wide range of customers.

(2) Preapproval, either formal or *de facto*, is becoming increasingly common.

States with existing preapproval authority are being asked to commit ratepayers to substantial expenditures. Even in states without a statutory mandate for preauthorization, utilities may voluntarily bring compliance plans to commissions in advance, in order to minimize business risk, and avoid the costly disallowances of years past. Finally, review and disallowance of pollution-control-related expenditures may be difficult if it can be argued that the actions were necessary to comply with state or federal laws. Under these circumstances, commissions have their best (and maybe only) chance to review and modify proposed utility actions prospectively.

Should commissions and public interest groups buy into prospective approval? A commonly-held view of preapproval is that it merely transfers business risk from the utility shareholder to the ratepayer. This view derives from the belief that preapproval involves obtaining a regulatory blessing on a given action or actions in advance. Although the approval of specific actions is certainly one outcome of the preapproval process, it should not be the sole or even principal outcome. The main focus of preapproval should involve defining an economic and institutional framework for how utilities, with input from regulators and the public, can best meet future customer needs. By focusing on the process (which can be controlled) instead of the outcomes (which are subject to numerous forces beyond control), regulation proceeds in a more orderly and fair manner. In the past, utilities have been penalized financially because certain actions did not turn out as planned, in some cases due to circumstances beyond the utility's control. In these cases, regulators and the public almost always overlooked the process that led to the outcome, focusing instead on the outcome itself. This resulted in large disallowances, disrupted planning, years of costly litigation, and an extraordinary amount of ill-will between utilities, regulators, and the public. Some disallowances have clearly been well-deserved, and preapproval neither relieves a utility's obligation to carry out its plans prudently nor the regulator's to insure that the public interest has been protected. Done correctly, the preapproval process provides a meaningful, preexisting context which can be used to analyze outcomes. CAAA compliance represents the next wave of large utility expenditures; the industry does not need another round of protracted prudence cases, particularly given the relatively precarious state of the economy and the nonproductive nature of most CAAA-related expenditures. Commissions and the public should consider seriously the benefits of examining utility plans in advance. Mutually planned actions should prove less controversial and less costly in the long run, even if the future turns out differently than now assumed.

(3) Without adequate review market opportunities may be ignored and compliance costs increased unnecessarily.

Title IV presents a novel opportunity to lower the cost of cutting sulfur dioxide (SO_2) emissions by the creation of a nationwide bubble and companion market mechanism. Utilities having the lower cost of control should overcomply and sell excess allowances to those with higher costs. As with bulk power markets, both sellers and buyers should benefit from the scheme. Initial compliance filings, however, indicate that some utilities plan to rely on traditional command-and-control approaches to achieving compliance with the CAAA's first phase, potentially overlooking purchasing allowances as an option. This can be partially attributed to the evolving allowance market. Some utilities, however, have established allowance self-sufficiency as a primary criterion for developing compliance strategies, and explicitly reject purchasing allowances as a means of compliance. If the acid rain title is to achieve its environmental objective cost-effectively, utilities must be indifferent to the origin of emission allowances. Allowance purchased must be considered along with those generated by building scrubbers or by switching fuels; cost should be the prime selection criteria. If purchasing appears to be cheaper than building a scrubber, purchasing should be the strategy. If each utility opts for self-sufficiency, ratepayers will pay more than necessary to achieve the environmental objectives set forth by Congress. Unless commissions prod utilities into examining all options (especially the market-based options), opportunities to reduce ratepayer costs will be lost.

Commissions can and should conduct independent review and analysis and decide on the reasonableness of proposed utility actions; the risk of not doing so is great. How can commissions, state utility consumer advocates, and public interest groups (especially those with limited staff and meager resources), wade through the mountains of utility data, and make a reasonable, defensible, independent determination? In this paper, the author proposes a regulatory framework for reviewing CAAA compliance plans, either prospectively or retrospectively, with limited staff and modest resources. This framework begins with a short checklist of questions that interested parties should explore, a description of the analytical issues that arise and suggested means of addressing them, and finally, criteria to be applied in judging the reasonableness of utility compliance plans. The ways in which CAAA compliance costs should be factored into IRP are briefly discussed, focusing on their effect on system avoided costs, and in turn, on demand-side management (DSM) resource selection and program design, on buyback rates for cogenerators or independent power producers (IPPs), and on system dispatch.

CAAA Compliance Plan Review

The framework suggested by the author can be applied whether CAAA compliance review occurs in a special docket, within an ongoing IRP case, or in periodic rate cases. Once the analysis is conducted, it need not be duplicated for other uses (although information may need periodic updating). Three fairly straightforward questions should be addressed in this analysis.

- Has the utility analyzed an adequate range of compliance options?
- Has the utility compared the various alternatives using reasonable assumptions and appropriate cost-effectiveness procedures?
- Has the utility appropriately characterized the risks of various alternatives?

Clearly, each of these questions subsumes a number of subsidiary issues, which will be discussed below. If these three broad questions are borne in mind (and, of course, answered) regulators and the public have a basic framework from which to proceed.

Emission Reduction Alternatives: How Much is Enough?

Formerly, a utility would have exhausted the range of available emission reduction options by considering a single scrubber technology and a small number of fuel-switching options. The number of technical options available to utilities has increased; each should be considered in a comprehensive emission reduction strategy. Scrubbers with both disposable as well as recoverable byproducts should be analyzed, particularly given the increasing difficulty of siting and permitting landfills in many areas. Repowering options that decrease SO_2 emissions should also be considered, particularly by utilities that are planning to retire capacity and add new capacity. The appropriate context for considering repowering options is IRP; if considered from a CAAA perspective alone, the results will be misleading and options that are cost-effective when new capacity needs and emission reduction obligations are considered, simultaneously will be incorrectly rejected.

The purchase and sale of allowances is new to the pantheon of emission reduction options. As stated earlier, allowances are fungible and those purchased are as viable as those generated by building a scrubber for complying with the law. The question of overcompliance, with an eye toward sales of the surplus or banking for future use must be considered. In addition, several derivative allowance markets are expected to form, making a place for allowance futures and options in the list.

Title IV also gives special prominence to energy efficiency and renewable resources as emission reduction options. Bonus allowances can be earned through early conservation efforts. Energy conservation can be used as compensating generation if a reduced-utilization strategy is pursued for phase 1 compliance; for utilities with high-emission-rate affected units, the value of conservation may be especially great here.

Finally, energy efficiency may have its greatest value after the year 2000, when virtually all units are affected, and the nation's utilities are under a permanent SO_2 emission cap.

It might legitimately be asked whether all options should be considered in all circumstances. Clearly, not all options are applicable to all sources, but all are potentially applicable in a given utility system. Not all options will ultimately prove cost-effective; a preliminary cost-effectiveness evaluation should be conducted before options are eliminated from consideration. Prescreening, in which options are rejected on intuitive grounds, often results in incorrect elimination of options. Although there are cases where intuitive prescreening is justified, they are comparatively few. Because the effort involved in conducting an initial cost-effectiveness evaluation is relatively small, it should be done on a comprehensive list of alternatives, not one that has been prescreened according to unstated criteria.

Table 1 is a checklist of the options that should be included in a comprehensive CAAA plan. Several manufacturers exist for each of the scrubbing technologies listed; considering more than one technology is appropriate. Likewise, there are a number of sorbent injection processes to consider. There are also a number of hybrid technologies that reduce SO_2 and nitrogen oxide emissions simultaneously that are not listed but are appropriate to consider.

The author does not consider third-party financing an essential element of a compliance plan (although there are those that do). This is an option that is being considered by a number of utilities and being pushed by some commissions.

Assumptions, Analytical Methods, and Evaluation Criteria

Once an adequate range of options is defined, the job of reviewing the assumptions used to characterize options and the analytical methods used to compare them begins. As with most utility planning analysis, it must be remembered that numerical precision is almost always an artifact of computing capability, and not a representation of fact. Anyone with a computer, spreadsheet software, and a laser printer can turn out volumes of numbers that have three decimal places; this does not

TABLE 1

SO_2 EMISSION REDUCTION OPTIONS

Technical Options

- Flue-Gas Desulfurization Technologies
    - Wet recoverable process (several technologies)
    - Wet disposable process (several technologies)
    - Dry process
- Sorbent Injection
- Fuel Switching
    - Low sulfur coal
    - Gas co-firing
    - Gas firing
- Clean Coal Technology/Repowering Options
    - Atmospheric fluidized bed combustion
    - Pressurized fluidized bed combustion
    - Integrated gasification combined cycle

Market Options

- Allowance transactions
    - Allowance purchases
    - Allowance sales
    - Derivative markets--futures, options

Other Alternatives

- Energy efficiency
- Renewable resources
- Third-party financing and ownership for technical options

make them correct, unfortunately, or even very useful. Three goals of utility planning analysis are:

- Good analysis should tell us where the break-points are between various alternatives, not the cost of a single alternative, carried out to three significant figures.
- Good analysis should seek to illustrate the key sensitivities of each major variable.
- Good analysis should attempt to define the limits of the problem being studied; to illuminate, not obscure.

In light of these goals a preference for simple models over complicated ones seems desirable. "Model-everything-in-the-world"-type models whose algorithms are proprietary and which must be run and maintained by members of a trained priesthood are too difficult for most readers to follow. Commissions and public interest groups should be able to get by with the following tools: commercially available spreadsheet software, a knowledge of utility economics and cost-effectiveness procedures, curiosity and well-developed skepticism. A production simulation model is nice but not essential. Although commission staffs and public interest groups benefit by doing their own research, an acceptable alternative involves defining scenarios and having the utility analyze them on behalf of the commission or intervenors using utility-owned or sponsored tools.

Table 2 provides a list of the main assumptions that will drive an analysis of emission reduction options.

All assumptions should be clearly laid out in the utility filing. If they are not, the first step of the review involves making sure that the utility provides the data in an appropriate, easy-to-comprehend format. Assumptions should be reviewed for consistency, compared to those contained in other filings and in publicly-available documents. The Electric Power Research Institute (EPRI) offers a variety of publications that contain generic cost and performance estimates for emission reduction technologies. EPRI publications are typically available free-of-charge to commissions.

TABLE 2

KEY ASSUMPTIONS

Costs

- Capital (dollars per kilowatt--$/kW)
- Fixed operation and maintenance ($/kW-year)
- Nonfuel variable operation and maintenance (dollars per megawatthour--$/MWH)
- Fuel cost ($/MWH)
- Allowances ($/year)

Technical

- Unit capacity factor, through time (%)
- Baseline SO_2 emission rate (pounds SO_2 per million British thermal units--mmBtu)
- Impact of various technical options on unit performance (kW lost, % increase in heat rate)
- Baseline unit heat rate (Btu/kWh)
- Baseline unit capacity (MW)
- Removal efficiency technical options (%)

Economic

- Fixed charge rate
- Inflation rate
- Escalation rate

Cost assumptions should be underlain by a similar level of detail. For example, it is inappropriate to use fuel price forecasts to estimate the cost of particular low-sulfur fuels in the same analysis as detailed engineering estimates for the cost of scrubbers. This is especially important if the costs of these options are relatively close. The utility should obtain price quotes from potential fuel suppliers, rather than rely on generic data. Under some circumstances, test-burns should be carried out to determine the compatibility of specific fuels with specific boilers. In the same way, the utility should go through the process of soliciting and reviewing bids for providing allowances; absent this exercise, allowances will not compete fairly with other options. This is especially critical for utilities that have high marginal emission reduction costs for which allowance purchases may offer substantial cost savings.

Estimates of forecasted unit-capacity factors come from production simulation runs. The cost-effectiveness of emission reduction options is very sensitive to the operation level assumed for the unit being analyzed. A high unit-capacity factor results in a lower cost (in terms of dollars per ton of SO_2 removed) than a lower capacity factor, all other things equal. One simple means of treating this problem is by assuming a constant capacity factor at all plants for screening purposes. A reasonable range for this assumption is from 60 percent to 70 percent.

Once all the utility assumptions have been reviewed, a range of sensitivities should be defined. These sensitivities should be designed to answer questions like these:

- What happens if low-sulfur coal is less expensive than the utility predicts?
- What happens if disposing of scrubber sludge costs \$20 per ton instead of \$10 per ton?
- What happens if the capital cost of the scrubber is \$275 per kW instead of \$200 per kW?

Having defined sensitivities, they must be analyzed. What analytical tools should be used?

Emission reduction alternatives should, for the most part, be ranked using a common metric, most often marginal dollars per ton of SO_2 removed. Analysts disagree over whether real or constant dollars should be used; the author believes it is merely important to be consistent. A simple spreadsheet can be used to perform this calculation for particular technical options and can be used to test numerous sensitivities quickly. Figure 1 is an example of such a spreadsheet.

SAMPLE EMISSION REDUCTION SPREADSHEET

Installed capacity (MW)	500
Annual capacity factor	0.6
Annual generation (gigawatthour--GWH)	2628
Heat rate (Btu/kWh)	12500
Baseline emission rate (pounds SO_2/mmBtu)	6
Baseline emissions (tons/SO_2)	98550
Capital cost ($/kW)	300
Variable O&M Cost ($/MWH)	5
Fixed O&M ($/kW-year)	14
Fixed charge rate	0.135
Annual cost	40390000
Heat rate penalty (%)	0.03
Secondary emission rate	0.6
Secondary emissions	10150.65
Tons reduced	88399.35
$/ton removed	456.9038

FIGURE 1

A more complicated spreadsheet application can also be developed to build a model that ranks numerous options on the basis of marginal emission reduction cost.

The spreadsheet must have macro capability to carry out repetitive calculations; the result of such a model is a ranking of technical options, which represents a cost-curve for emission reduction alternatives. Allowance purchases are factored into the analysis, on the basis of bids or estimates of market prices.

Repowering is a special case. Since repowering options provide benefits in the form of capacity and energy, along with emission reductions, they cannot be analyzed in this framework without producing erroneous results. Repowering presents the most compelling reason for combining IRP and CAAA planning. If these activities are separated, repowering capacity and energy-related benefits must be segregated, and the remainder attributed to CAAA compliance. If this segregation can be carried out unambiguously, the emission reduction portion can be integrated into a strict CAAA compliance analysis.

Energy efficiency cannot be analyzed neatly within this framework, for some of the same reasons just described for repowering. Energy efficiency mainly provides benefits in the form of capacity and energy; the emission reductions created through efficiency ARE clearly valuable, but not enough by themselves, to justify the programs.

Energy efficiency may be a viable emission reduction alternative under the special circumstances created by the reduced utilization provisions, contained in section 408 of the CAAA. If a utility has adequate generation capacity and if its transmission system does not necessitate the operation of particular plants, it is clear that a substantial number of allowances can be freed-up through reduced utilization. In a study prepared for the EPA Global Change Division, the authors analyzed a reduced utilization scenario for one of the power plants in the American Electric Power (AEP) System. In this analysis, conservation was assumed to reduce the generation at AEP's Kammer plant, which has an emission rate of approximately seven pounds of SO_2 per mmBtu. This approach created thirty-five allowances per GWH conserved, as opposed to one to five allowances if conservation was assumed to occur at the system margin. This strategy may be especially attractive for systems with older, affected units having high baseline SO_2 emission rates, high emission-reduction costs and ongoing energy efficiency efforts.

When the number-crunching is complete, the time comes to decide upon the best strategy. Cost-effectiveness is clearly the most important criteria. The following questions should be answered:

- Is the cost (in dollars per tons of SO_2 removed) in a reasonable range?
- Does the cost stay within a reasonable range when subjected to sensitivity analysis?

In some analyses which were reviewed, the cost-effectiveness of all strategies studied, clusters in a narrow range. Often this reflects the way in which assumptions are chosen; sensitivity analysis should allow the analyst to ferret this out. In other cases, alternatives have similar costs, irrespective of the sensitivities applied. Then the criteria for selecting a plan are less clear cut.

In the same way that utilities prefer to rely on a diverse generation mix, it may be appropriate to diversify the emission reduction strategy. For utilities having multiple affected sources this may be an appropriate criteria, leading to a combination of scrubbing, fuel switching, and allowance purchases. Alternatively, a utility may have the ability to achieve compliance for its entire system by a single action (usually the installation of a scrubber on a very large plant). From a logistical standpoint, this may be superior to a strategy involving numerous actions. It may be preferable to lock into the fixed-cost stream that technical solutions such as scrubbers offer, instead of the potential price run-ups associated with long-term fuel contracts. Maximum exposure due to fuel-cost increases, can, on the other hand, be derived from existing or proposed fuel contracts. Finally, local or state concerns, such as protection of an indigenous coal industry, may be an important factor.

If the costs of alternate strategies are tightly grouped and independent analysis demonstrates that the risk of the strategies is roughly equivalent, the utility-preferred action should be approved. Concluding that a utility's preferred strategy is acceptable is neither an indication of faulty analysis nor proof that the effort put into independent analysis was a waste of time. Independent analysis undergirds a higher level of regulatory decisionmaking, and improves the regulator's level of accountability to the public.

CAAA Compliance Costs and IRP

Compliance costs become components of the benefit-cost calculus that is at the heart of IRP. CAAA costs figure into resource screening, DSM program design and determination of buy-back rates for cogenerators and IPPs. CAAA costs can be costs or benefits, depending upon whether the resource considered increases or decreases SO_2 emissions. The following table (Table 3) classifies resources according to whether they typically increase or decrease emissions.

TABLE 3

CAAA COMPLIANCE: COSTS OR BENEFITS ?

- Resources that decrease emissions
    - High-load-factor energy-efficiency programs
    - High-load-factor power purchases from non-SO_2 emitting sources
- Resources/actions that increase emissions
    - New SO_2 emitting generation
    - Some load management
    - Load building programs
    - Firm energy sales

For those resources that reduce emissions, the number of SO_2 allowances freed-up appears as a credit in the benefit-cost calculus. In the case of DSM program screening, this increases the cost-effectiveness threshold; for DSM program design, this increases potential penetration levels or rebate levels. In the case of power purchases from nonsulfur-emitting cogenerators or IPPs, the credit should appear in the purchased power contract. For those resources that increase emissions, the number of allowances consumed appears as a cost in the benefit-cost calculus.

A utility production simulation model is used to estimate the number of allowances freed-up or consumed. The time-differentiated load characteristics of the resource or action in question are defined and the system is modeled with and without the resource. In the case of a DSM program, for example, the system is modeled before and after the program is in place. The difference in SO_2 emissions between the two runs is credited to the DSM program. The effect of a given energy-efficiency program is highly system-specific. Key variables include the existing and planned generation mix and the marginal SO_2 emission rate. Our analysis of the effect of selected energy efficiency programs on SO_2 emissions of four midwestern utility systems indicated that a typical commercial lighting program, with a peak impact of 100 MW, reduced between 1,000 and 6,000 tons of SO_2 per year. Figure 2, below, depicts these findings.

At $500 per allowance, the allowance benefit adds from 1.5 mills to 2 mills to the energy value of conservation. If avoided energy costs are in the neighborhood of 2 cents per kWh, accounting for allowances represents an increase of nearly 10 percent.

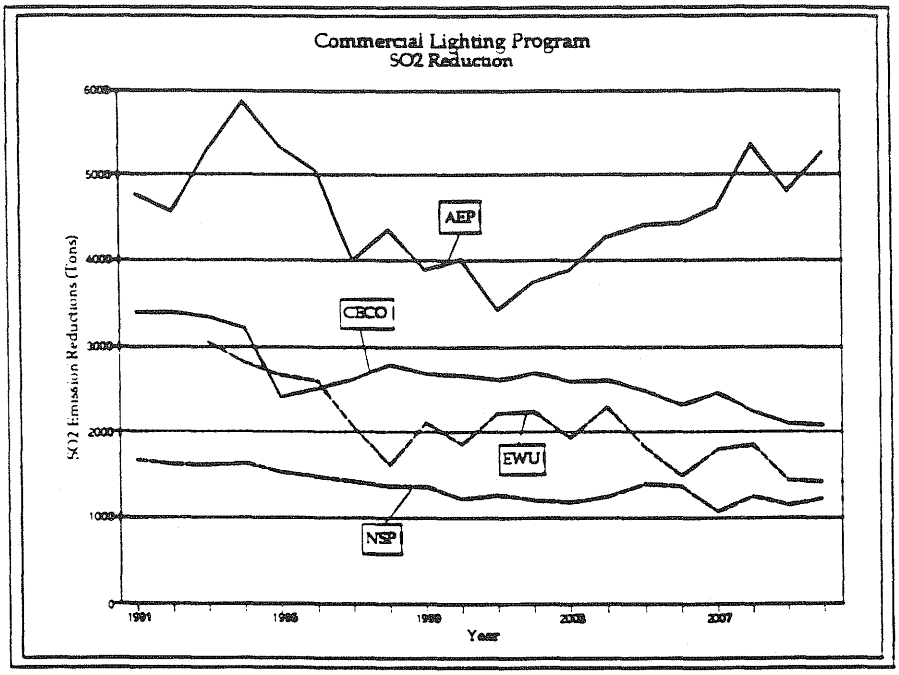

Fig. 2. SO_2 emission reductions resulting in a 100 MW decrement commercial lighting program for four utility service territories.

THE ROLE OF INTEGRATED RESOURCE PLANNING, ENVIRONMENTAL EXTERNALITIES, AND ANTICIPATION OF FUTURE REGULATION IN COMPLIANCE PLANNING UNDER THE CLEAN AIR ACT AMENDMENTS OF 1990

by

Stephen Bernow
Bruce Biewald
Kristin Wulfsberg[1]

Overview

Utilities are developing sulfur dioxide (SO_2) emission compliance plans to meet the emission limitations of the Clean Air Act Amendments of 1990 (CAAA).[2] The compliance plans will have long-term effects on resource selection, fuel choice, and system dispatch. The use of integrated resource planning (IRP) is a necessity to ensure that compliance plans are consistent with the overall societal goals that IRP is expected to fulfill. In particular, environmental externalities must be integrated with the compliance planning process. The focus of the CAAA is on air pollution reduction, specifically acid gases and toxics, and attainment of National Ambient Air Quality Standards (NAAQS) for criteria pollutants. Title IV specifically focuses on sulfur dioxide with a national allowance trading system, while further regulation of toxics and nitrogen oxides is slated for additional study. Yet, compliance planning based narrowly

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[2] Clean Air Act Amendments of 1990, Title IV, Sec. 404(f)(2)(B)(iii)(I).

upon today's environmental regulations could fail to meet the broad goals of IRP if a larger array of environmental externalities is excluded from the analysis.

Compliance planning must consider a broad range of environmental effects from energy production and use for two principal reasons: (1) to protect society's long-term stake in environmental quality, and (2) to ensure that today's plans are rich enough to accommodate potential changes in regulation and national environmental goals. For example, a plan established today that does not address the carbon dioxide (CO_2) issue may have a resource mix that may be found to be unnecessarily costly several years hence if international and national goals for carbon reduction are adopted.

The explicit recognition of environmental effects, such as those associated with CO_2 release, will result in prudent compliance plans; plans that take advantage of current opportunities for pollution avoidance and have long-term viability in the face of regulatory change. By including such considerations, the mix of resources acquired and operated (supply and demand, existing and new, conventional and renewable, fuel type and fuel quality, pollution control, and dispatch protocols) will be robust and truly least-cost.

Introduction

In the year 2000, Title IV of the CAAA will limit the annual emissions of SO_2 from electric utility units in the United States to 8.9 million tons. In preparation for this limitation, which will be implemented in two phases, utilities are developing compliance plans to meet the emission requirements at the lowest cost. The novelty of the law is that it offers utilities considerable flexibility in choosing options for achieving the required reductions. The SO_2 emission allowance trading system established by Title IV will create a market for the emission permits allocated to utilities, encouraging the implementation of the most cost-effective reductions or prevention options first. Unused allowances may be traded or sold to utilities with higher marginal control or prevention costs, which may then use these permits as part of their least-cost compliance strategies.

In addition, the CAAA calls for reductions in nitrogen oxides, prepare for the regulation of toxic emissions, and implement improvements to realize NAAQS.

Recognition of the variety of alternatives available meet to the demand for energy services (demand-side management (DSM), renewables, cogeneration, independent power producers (IPPs)) has led to the regulatory evolution of IRP. The goal of IRP is determining a least-cost mix of traditional and alternative energy resources to meet future energy demand. Increasingly, IRP is including environmental externalities, motivated by the regulator and utility responsibility to ensure energy resource planning decisions serve the long-term interests of environmental protection, and account for environmental consequences which may not be represented by current resource costs. Although externalities are, by definition, costs that occur outside current market systems, accounting for them now may give utilities a cost advantage in the event of future environmental regulations. The utilities that began reducing SO_2 emissions years in advance of the CAAA are now in a position to meet their goals at less cost and to sell allowances outside their system, while those that continued to build coal plants during the 1980s may face higher compliance costs. Given this history, utility compliance strategies should consider environmental effects that go beyond those specifically addressed by the CAAA. Hand-in-hand with environmental externalities, utilities should anticipate further regulations eventually stemming from the CAAA, such as toxic emissions limitations as well as other environmental initiatives.

An excellent candidate for future emission regulation is CO_2. Although the emissions of CO_2 and other greenhouse gases are currently unregulated in the United States, their contribution to significant global climate change and related physical, ecological, economic, and demographic effects will likely require future abatement action. The production of electricity from fossil fuels is one of the primary sources for CO_2 emissions, and about 40 percent of U.S. CO_2 emissions come from the utility sector, overwhelmingly from coal-fired facilities. As utilities develop SO_2 compliance plans, the selection of control and prevention options will also affect utility CO_2 emissions. To ensure a socially optimal compliance plan, the possible compliance options are best addressed in an IRP process that explicitly addresses a broader array of environmental considerations than those indicated by the CAAA, and in particular, does not ignore the regulatory potential for emissions of CO_2 and other greenhouse gases.

The objectives and framework of IRP are ideally suited to CAAA compliance planning, the consideration of environmental externalities, and prudent anticipation of future environmental regulations. Inevitably, compliance strategies will influence a variety of environmental effects, and pollutant emissions besides SO_2--CO_2 in particular. The mistakes of traditional energy planning offer valuable lessons for compliance planning, just as the development of IRP emerged from the experience of costly resource planning decisions in the past. Unnecessarily high future costs arising from today's compliance planning decisions can be avoided by expanding IRP to include externalities such as carbon emissions from the start.

Least-Cost IRP

It has been suggested that the CAAA "could fundamentally change the IRP process at utilities," by requiring them to consider risk and reliability of compliance plans under the constraints of emission limitations.[3] However, a review of IRP fundamentals demonstrates that such considerations are already central to the precepts of IRP. Even before the CAAA, least-cost IRP expanded the directive of traditional utility planning. For example, NARUC's, *Least-Cost Utility Planning Handbook for Public Utility Commissioners*[4] calls for least-cost plans that strive to:

- minimize costs to all stakeholders;
- evaluate all resource options (supply, demand, fuel switching, cogeneration, and so on),in a fair and consistent fashion;

[3] D. M. Violette and Carolyn M. Lang, "Integrated Resource Planning and the Clean Air Act," in *Energy Efficiency and the Environment: Forging the Link*, D. Vine et al., eds., (American Council for an Energy-Efficient Economy, 1991), Chapter 9.

[4] National Association of Regulatory Utility Commissioners, *Least-Cost Utility Planning Handbook for Public Utility Commissioners* (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1988).

- create a robust, flexible plan that allows for uncertainty and permits adjustment as circumstances change.

Robustness to ensure risk minimization is one of the critical characteristics for an IRP.[5] The optimal energy plan is one that stands up under a broad range of future conditions. As the future diverges from current expectations, the planned resource mix should continue to be reasonably economical compared with alternative plans and, to the degree warranted, should afford flexibility for the rapid development of alternative resources. Robustness stems from selection of diverse energy resources, thereby decreasing the risk that there will be dominant resources which, under unexpected circumstances, can render a plan expensive and undesirable. Compliance planning, environmental externalities and anticipation of regulations entail risk management, suggesting that IRP is the most appropriate framework for compliance planning.

The CAAA requires least-cost planning as part of the eligibility requirements for the bonus allowances from the Conservation and Renewable Energy Reserve (CRER) (Title IV, section 404). More generally, state regulators could review capital projects (and operating costs) for compliance and trading strategies in the full array of regulatory hearings (IRP proceedings, rate cases, certifications of need, and prudency reviews) in which costs could be assessed. Compliance review is a natural extension of IRP and should be incorporated to secure the overall least-cost resource plan.

Coordinating compliance planning with IRP enables utilities to evaluate the full range of SO_2 reduction strategies. The allowance market encourages utilities to pursue systemwide compliance planning. Utilities are no longer confined to solely unit-specific pollution control. As such, they face an array of control technologies, resource options, and operating alternatives to meet the required reductions.

The CAAA does not require that state utility regulators review utility compliance plans but clearly this is essential in a least-cost IRP process to ensure the cost-

[5] Thomas H. Lee, Ben C. Ball, Jr., and Richard D. Tabors, *Energy Aftermath* (Boston, MA: Harvard Business School Press, 1990).

effectiveness of the compliance strategy.[6] A least-cost compliance plan should be embedded in (or is actually equivalent to) a least-cost resource plan. Pursuing compliance planning as part of IRP will ensure a consistent economic evaluation of emission control technologies, DSM, utility operation, and other utility resources for both compliance and for meeting the demand for energy. In addition, the tradeoffs in performance (reliability, planning flexibility, and so on) and environmental and human health externalities must be included to guarantee costs to society are minimized, for a true societal least-cost plan.

All of the above observations argue for joint integrated resource/compliance planning (IRCP). Each compliance planning option carries with it different risks, both to individual utilities and society as-a-whole. The economic benefits of the allowance trading system will not be realized if utilities engage in overly risk-averse behavior and hoard emission allowances. Society will ultimately suffer if the lack of a vigorous allowance market limits the development of new, cleaner resources and inhibits the pursuit of low-cost mitigation strategies. Successful IRCP must consider emission allowances as a new utility system commodity, requiring a forecast of the emission market, an evaluation of the market opportunities, and a comprehensive evaluation of the externalities associated with the use of allowances.

To realize the potential benefits of emission allowance trading it is necessary that the fullest use is made of an unconstrained market. Thus, it is important that state utility and/or environmental regulators do not impose unnecessary restrictions on the ability of electric utilities to buy and sell allowances.[7] The term "unnecessary," however, is subject to interpretation and policy judgement. Just as the full benefits of economical power pooling may be limited by local environmental constraints, so too might CAAA

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[6] C. W. Bartels and Richard A. Rosen, *The Clean Air Act Amendments of 1990 and Utility Least Cost Planning: Issues for State Regulators* (Boston, MA: Tellus Institute, 1991).

[7] For example, the hoarding of allowances should not be dictated by commissions unless a certain amount of banking of allowances is found to be a component of an IRCP.

compliance costs be higher than the minimum achievable with unconstrained trading, if a particular state's policy is to limit emissions more strictly than Title IV of the CAAA would entail.[8] Presumably, the extra costs would be borne by the citizens of the state that chose that policy. Thus, state policy will decide where the tradeoff between local electricity costs and emissions ought to be, always satisfying the CAAA as its minimum requirement.

The uncertainty related to compliance planning accelerates the need to have IRCP in place across the country as a utility risk-management tool. The iterative process of assessing resource plan performance under various assumptions about the external environment inherent to IRP,[9] will enable utilities to evaluate both the options and their risks. IRP encourages the implementation of a broadly-based energy strategy, relying on diverse resources to realize low cost at low risk; similarly IRCP may promote the use of many emission reduction options to achieve these ends. IRCP formalizes the incorporation of environmental externalities (whether that is additional SO_2 reductions to meet stricter targets, releases of air toxics, or emissions of greenhouse gases)as a critical dimension of both the least- (societal) cost and risk mitigation aspects of IRCP.

Externalities in Compliance Planning

The implementation of cost-effective IRCP must account for all of the real costs of energy. The production and consumption of energy have many effects that currently lie outside the resource decisionmaking perimeter: pollutant emissions are linked to human and environmental damages, depletion of nonrenewable resources threatens economic sustainability and national security, poor efficiency and imprudent investments

[8] A state may decide that it wishes to restrict emissions (or deposition) within its boundaries below that which would result from least-cost compliance.

[9] C. Goldman et al., *Least-Cost Planning in the Utility Sector: Progress and Challenges*, LBL-27130, ORNL/CON-284, (Berkeley, CA: Lawrence Berkeley Laboratory and Oak Ridge National Laboratory, 1989).

drive energy prices up and endanger economic competitiveness. The costs to society associated with each of these and other effects may be formidable. The list below illustrates the range of environmental effects possible from exposure to a few of the air emissions associated with energy resources:

- **Local Air Quality**. Although NAAQS exist for seven "criteria pollutants" to ensure adequate protection of human health and welfare, hundreds of areas across the country exceed the regulated limits. Moreover, various toxic metals emissions currently not regulated in the NAAQS have adverse effects on human health and the environment. Visibility, human health, wildlife, and ecosystems are all subject to degradation given poor air quality.
- **Regional Acid Deposition.** The emissions of acid gases released during the burning of fossil fuels can damage natural and man-made environments by acidifying soils, lakes, rivers, and estuaries; by directly attacking trees, and by degrading man-made materials such as buildings and statues. Measures to improve local environments, such as tall stacks, have resulted in the export of the pollution and damages elsewhere.
- **Global Climate Change.** The buildup of anthropogenic emissions including CO_2, methane, nitrous oxide, and chlorofluorocarbons may be precipitating an increase in the earth's temperature. The change in temperature could lead to significant changes in land use, climate, weather patterns, animal populations, and ecosystems. Serious demographic, economic, infrastructural, and political consequences could ensue.

Currently, the regulations and standards governing energy production and consumption generally fail to internalize the costs of pollution. This occurs because: (1) the levels currently allowed for particular pollutants often fail to provide complete protection, (2) regulations do not address all of the harmful pollutants, and (3) the regulatory mechanisms used often fail to provide proper incentives (for example, through price signals). From a societal perspective, alone or in combination, these factors may result in suboptimal emission levels and distort resource allocation.

Although the purpose of Title IV of the CAAA is to reduce the effects of acid deposition on a national scale, the purpose of IRCP with externalities is to identify the societal least-cost resource plan over time. The CAAA does not obviate the consideration of residual SO_2 emissions that meet compliance standards. The national cap fails to address the local and regional effects of SO_2 transport. For states such as New York which has taken steps to protect "sensitive receptor areas," the effects of one ton of SO_2 released at different locations are not equal. The free trading of emission allowances may result in undoing the work of New York's State Acid Deposition Control Act, which was designed to limit New York's contribution to acid deposition at its in-state sensitive receptors.[10] Although the establishment of a national cap is an important step toward internalizing environmental externalities, compliance does not preclude further consideration of SO_2 emission effects from resource and compliance decisions.

Similarly, compliance with regulations governing other pollutants, such as the NAAQS' air pollutant facility standards criteria, does not mean that the permissible residual emissions have no effect on human health and welfare. For several reasons, current standards fall short and allow levels of pollution that are inconsistent with full protection of the environment and public health. For example, ambient air quality standards in the U.S. are determined for specific pollutants such that they *should* have *de minimis* effects on human health and welfare. However, the existing standards for the criteria air pollutants are based on uncertain threshold levels; consider only the *current* knowledge of health effects due to pollutant exposure; generally overlook cumulative, additive, synergistic, and long-term exposure effects; and do not necessarily protect the more susceptible members of the population.[11]

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[10] New York State Energy Office, Department of Public Service, Department of Environmental Conservation, New York State Energy Plan, Draft, *Environment*, Biennial Update, Volume III, Issue 8 (1991).

[11] For example, in its ongoing analyses of the issue, the EPA has recently found that there may be no threshold level for dioxin, contrary to its earlier findings on this matter.

Environmental regulations can be designed to provide incentives for polluters to decrease emissions to socially "optimal" levels. For example, if pollution taxes are charged to reflect the full cost of pollution damages in the costs of production, then the polluter will presumably make decisions to reduce pollution in cases where control is efficient (the control costs per unit of pollution are less than the damage costs of the avoided pollution) and to not reduce pollution in cases where control is inefficient (control costs are greater than avoided damage costs). Similarly, insofar as pollution costs would be reflected in consumers' energy prices, consumer investments and operation of energy-using equipment will be affected. Economically this is the "ideal" or "efficient" solution to externalities.

However, by reducing environmental costs to monetary terms along with other costs (in the economic paradigm) their physical specificity is lost and there is no guarantee that behavioral response to these additional costs (factor inputs, prices) will result in significant pollution reductions. Thus, an alternative approach to internalizing externalities is to establish system or regionwide environmental goals (for example, emissions caps) and creating mechanisms for efficient realization of those targets. One such mechanism is to assign property rights (as in the case of tradable emission allowances) and rely on a market in these permits to realize economic efficiencies.[12] With an allowance system and a working market, polluters will make decisions recognizing the "opportunity cost" of each unit of pollution.[13]

The situation is even more serious for pollutants that are currently unregulated. The process of setting standards requires extensive research to determine the causes, effects, and thresholds of pollutant emissions. Until such issues are resolved, pollutants such as toxic emissions and CO_2 remain unregulated, despite considerable concern for

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[12] With explicit and monitored systemwide targets, pollution taxes could be used as an instrument to meet those targets, and adjusted as evidence is accumulated on their efficacy.

[13] Even these approaches may not be sufficient to internalize all environmental externalities, and the need for more direct restrictions for some sources, pollutants, and impacts may remain.

their potentially deleterious effects. Current utility compliance decisions should not ignore these emissions simply because the regulations have not yet been developed and promulgated.

Anticipating Future Environmental Regulations

The likelihood of additional, more stringent environmental regulations is a significant and legitimate concern for energy and compliance planners. As a general policy for all energy decisionmakers, the Scientific Advisory Board to EPA has made the following recommendation:

> Environmental protection must be integrated into other policy areas, in as fundamental a manner as are economic concerns.[14]

Other agencies have addressed such concerns more specifically to utilities. The National Association of State Utility Consumer Advocates (NASUCA) clearly advises utilities to anticipate future legislation and minimize the risk of pursuing options that may later be deemed imprudent:

> Recent scientific and policy development convince us that the utility industry should be put on notice that its resource planning must take into account risks associated with continuing growth in greenhouse gas emissions. . .[F]ailure to realign resource planning and investment in this way will open those responsible to prudency challenges. . ..[15]

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[14] U. S. Environmental Protection Agency, Science Advisory Board (A-101), The Report of the Strategic Options Subcommittee, "Relative Risk Reduction Project," EPA SAB-EC-90-021C (September 1990), Appendix C.

[15] National Association of State Utility Consumer Advocates, An Open Letter to the Managers of the U.S. Utility Industry, RE: *Implications of the Greenhouse Challenge for Utility Planning, Financial Risks, and Future Prudency Reviews*, dated January 31, 1991.

Similarly, the Electric Power Research Institute has advised utilities to anticipate probable toxics regulations when making compliance decisions.[16]

In September 1992, the Wisconsin Public Service Commission ordered the state's utilities to assign dollar values to the emissions of greenhouse gases as a way to estimate the real monetary costs of compliance with future national or international regulation and represent such costs in resource planning.[17] The merits of this action may be demonstrated sooner than the Commission expected with the Federal Administration's announcement in April 1993 committing the United States to reducing its greenhouse gas emissions to 1990 levels by the year 2000.[18]

Until all pollutants are efficiently regulated, utility planning should recognize the shortcomings of current environmental regulations, anticipate their future evolution, and select resources based upon their full costs, including damages to the environment and human health. By analyzing both demand and supply and accounting for environmental effects, social effects, risks, and uncertainties, the least-cost planning paradigm can determine the optimal resource plan that provides electric service to the public.[19] There are several advantages to developing IRCP with the additional objective of reducing externalities, including:

- opportunities for pollution prevention,
- integration of compliance with systems operations and planning,
- diversity of energy resources,
- minimization of risk of regulatory change, and
- minimization of risk of irreversible human health, welfare, and environmental damage.

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[16] Electric Power Research Institute, "Utilities Advised to 'Think Toxics' when Deciding Acid Rain Strategies," *Utility Environment Report* (November 15, 1991).

[17] Wisconsin Public Service Commission, *Advance Plan 6 Order*, Docket No. 05-EP-6 (September 1992).

[18] "Industry Wary on Clinton Global Warming Plan," *Electric Utility Week* (April 26, 1993).

[19] NARUC, *Least-Cost Utility Planning Handbook*.

Just as the IRP requires the equal consideration of multiple utility options (supply/demand, planning/operation, new/retrofit facilities, conventional/renewable resources) compliance options should be evaluated on a level playing field. Different compliance options (flue gas desulfurization, fuel substitution, conservation, environmental dispatch) have very different emission characteristics. During the planning stage, the choice of resources can realize opportunities for pollution prevention at a lower cost than can be achieved through plant-specific abatement technologies that in the past have been the primary tool of environmental regulators.

A broader externalities policy will encourage alternative resource/compliance strategies, integrating both planning and operations (for example, emissions constrained or total-cost dispatch) and further diversifying the utility resource mix.[20] The prospects for cleaner advanced supply technologies, fuel switching, renewables, energy efficiency, and demand management, beyond that required by Title IV itself will be improved.

The use of alternatives such as DSM and renewables also offers additional regulatory benefits. The CAAA extends bonus allowances to utilities using qualified energy conservation and renewable technologies as a compliance strategy for phase I units. At least eighteen states have adopted regulatory incentives to encourage energy conservation.[21] As with all options, DSM and renewable technologies are not without risk, but a comprehensive compliance planning process should take into account all of the advantages, including greenhouse gas and other environmental effect reductions.

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[20] Diversity of energy and compliance resources has both advantages and disadvantages. Relying on a small number of compliance options (for example, scrubbers at a few plants) increases the risk of failing to comply should those options be insufficient. A variety of options spreads out the risk of compliance failure but requires utilities to undertake projects where they may have little experience, such as renewables and conservation.

[21] J. Kruger and Rick Morgan, U.S. Environmental Protection Agency, *The Clean Air Act Amendments and Energy Conservation*, presentation at NARUC 1992 Winter Meeting, February 27 through March 4, 1993, Washington, D.C.

The SO_2-CO_2 Tradeoff

While greenhouse gas emissions, and CO_2 in particular, are largely unregulated, their contribution to global climate change poses considerable environmental and economic risk:

> Global climate change will have significant implications for natural ecosystems; for when, where, and how we farm; for the availability of water to drink and water to run our factories; for how we live in our cities; for the wetlands that spawn our fish; for the beaches we use for recreation; and for all levels of government and industry. . .As a result, the landscape of North America will change in ways that cannot be fully predicted.[22]

This section illustrates the economic and environmental tradeoffs posed by compliance planning, focusing on the unregulated emissions of CO_2 as an important environmental externality. Based upon a series of compliance strategies in terms of their costs, SO_2 reductions, and CO_2 emissions, it is observed that:

- compliance options have very different net CO_2 effects,
- CO_2 reductions could be a "free lunch" or inexpensive, and
- SO_2 allowance trading could have important consequences for national CO_2 emissions.

As explained in the previous section, compliance planning should not be done in a vacuum, addressing only the objective of acid gas reductions. The available strategies for SO_2 reductions will put in place new resources and retrofit control technologies that have considerably different carbon emissions. For example, scrubbers reduce SO_2 while increasing CO_2 emissions by reducing power plant efficiency (increasing heat rates), while fuel switching to low-sulfur coal will reduce SO_2 with essentially no effect on carbon emissions. Fuel switching from high-sulfur-(and carbon) content coal to gas

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[22] U.S. Environmental Protection Agency, *Potential Effects of Global Climate Change on the United States*, PB89-161046 (Washington, D.C.: U.S. Environmental Protection Agency, 1988), Executive Summary (DRAFT).

combustion at the power plant will essentially eliminate the plant's SO_2 emissions while approximately halving its carbon emissions; DSM, cogeneration and end-use fuel switching have their own SO_2, carbon, and cost tradeoffs. Finally, there are system effects on emissions and costs that result from plant-specific changes in fuel efficiency and pollution control, as well as end-use-specific changes affecting the load shape. With broad foresight, utilities can invest in decisions that will serve both the interests of acid gas and greenhouse gas reductions at least cost, taking full advantage of opportunities for cheap pollution prevention now instead of paying later due to more stringent regulations or general environmental decline.

Two studies demonstrate the tradeoff between SO_2 and CO_2 emissions strategies in compliance strategies. The first, a study using a model of the New York Power Pool, concluded that placing constraints on carbon emissions dramatically reduces the use of scrubbed and new coal capacity for SO_2 emission reductions, and replaces it with direct investment in more efficient electrical equipment.[23] Compliance plans would thus change considerably depending upon the set of emissions considered: acid gases alone or in combination with CO_2.

Similarly, results from a study of the New England electric system conclude that strategies to meet performance, cost, and emission reduction goals must target:

- future and existing resource needs,
- demand-and supply side options,
- technological and operational improvements.[24]

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[23] Timothy D. Mount and Martha E. Czerwinski, *Global Warming and Acid Rain: The Implications for Restricting Emissions from Power Plants* (Ithaca, NY: Cornell University, Department of Agricultural Economics, 1989).

[24] Stephen R. Connors, *Reducing Atmospheric Insults Without Going Broke: How to Halve Acid Rain and Ground-Level Ozone Precursors from New England's Electric Power Sector*, presented at the "Trace Substances in Environmental Health" Conference, May 20-23, 1991, Columbia, Missouri.

Indeed, the New England study echoed the call made by two of the authors of this paper, for expanding the boundaries of IRP (which are currently focused on the procurement of new resources) to incorporate existing resources and operational practices.

To illustrate the SO_2/CO_2 tradeoff, a series of compliance strategies for phase I was analyzed, showing that:

- they have different net CO_2 emissions, and
- reductions in CO_2 may be had at low cost.

With the addition of allowance trading there is an important additional observation: system trading of allowances may have serious effects on net CO_2 emissions, suggesting the need for a national system for CO_2 emissions.

The analysis is based on a 1991 NASUCA report, *Emissions Trading Handbook.*[25] The report includes a review of a variety of compliance strategies for both phases of the CAAA for Illinois Power. The illustration uses the phase I compliance strategies hypothesized for this utility. Illinois Power is described in 1990 as serving a 1,985 MW load, generating 17,320 gigawatt. Given 196,000 allowances in phase I, and anticipating approximately 370,000 tons of SO_2 emissions in 1995, the utility must achieve a reduction of 174,000 tons. The possible compliance strategies undertaken between 1990 and 1995 are characterized below by their principal compliance options:

- Flue Gas Desulfurization (FGD). All of the compliance strategies included one scrubber installed at a 564-MW unit. FGD strategies installed scrubbers at additional units.
- Fuel Switch to Natural Gas. Four coal units are switched to natural gas.
- Fuel Switch to Low-Sulfur Coal. One 216-MW high-sulfur coal unit is switched to low-sulfur coal.
- Natural Gas Repowering. One 216-MW high-sulfur coal unit is repowered as a natural gas combined-cycle unit, with the addition of 210 MW of capacity.

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[25] Ray Czahar et al., National Association of State Utility Consumer Advocates, *Least-Cost Utility Planning Handbook for Emissions Control and Acid Rain Compliance*, prepared by Economic and Technical Analysis Group, and Independent Power Corporation, 1991.

- Moderate Conservation. A 25 percent reduction of load growth over the five-year period (1990-1995), resulting in a 4 percent reduction in energy demand. Only very cost-effective programs are considered, assumed to have an average annualized cost of 1 cent per kilowatthour (kWh).
- Aggressive Conservation. A more aggressive conservation program, approximately double the cost of the moderate strategy. Load growth is essentially flat, and energy savings are roughly 13 percent.
- Emissions Dispatch. All of the scenarios utilize some degree of emissions dispatch. The computer dispatch simulation used an optimization objective combining two weighted considerations: least-cost and least SO_2 emissions.

Because the text of the *Emissions Trading Handbook* is concerned with presenting the costs associated with SO_2 reductions, there is not any detail presented on the CO_2 emission effects. The authors estimated these effects by first estimating the SO_2 emissions expected for each option of the alternative compliance strategies. Because the exact dispatch of units is not given in the report, the authors' assumptions may not correspond to the reported strategies and the corresponding strategy costs. However, the authors believe these are conservative CO_2 assumptions and it is not unreasonable to combine them with the reported strategy costs.

Figure 1 plots the SO_2 and CO_2 emissions for the different strategies. Although each strategy roughly achieves the desired SO_2 reductions, there is a wide variation in net CO_2 emissions, ranging from a reduction of nearly 2,500,000 tons CO_2 per year to an increase of approximately 1,250,000 tons per year. The installation of scrubbers, with their heat-rate penalty, results in the highest CO_2 emissions, and not surprisingly, the highest level of conservation results in the lowest CO_2 emissions. Gas repowering and moderate conservation have similar CO_2 emissions because of the reliance on natural gas generation; repowering displaces coal generation with the gas-fired combined cycle, and moderate conservation assumed considerable emissions dispatch (natural-gas-fired generation) to achieve the reported SO_2 reductions.

Figure 2 plots the CO_2 emissions by the annualized cost of the compliance strategy. Here, not only do the strategies range in CO_2 emissions but they also range in

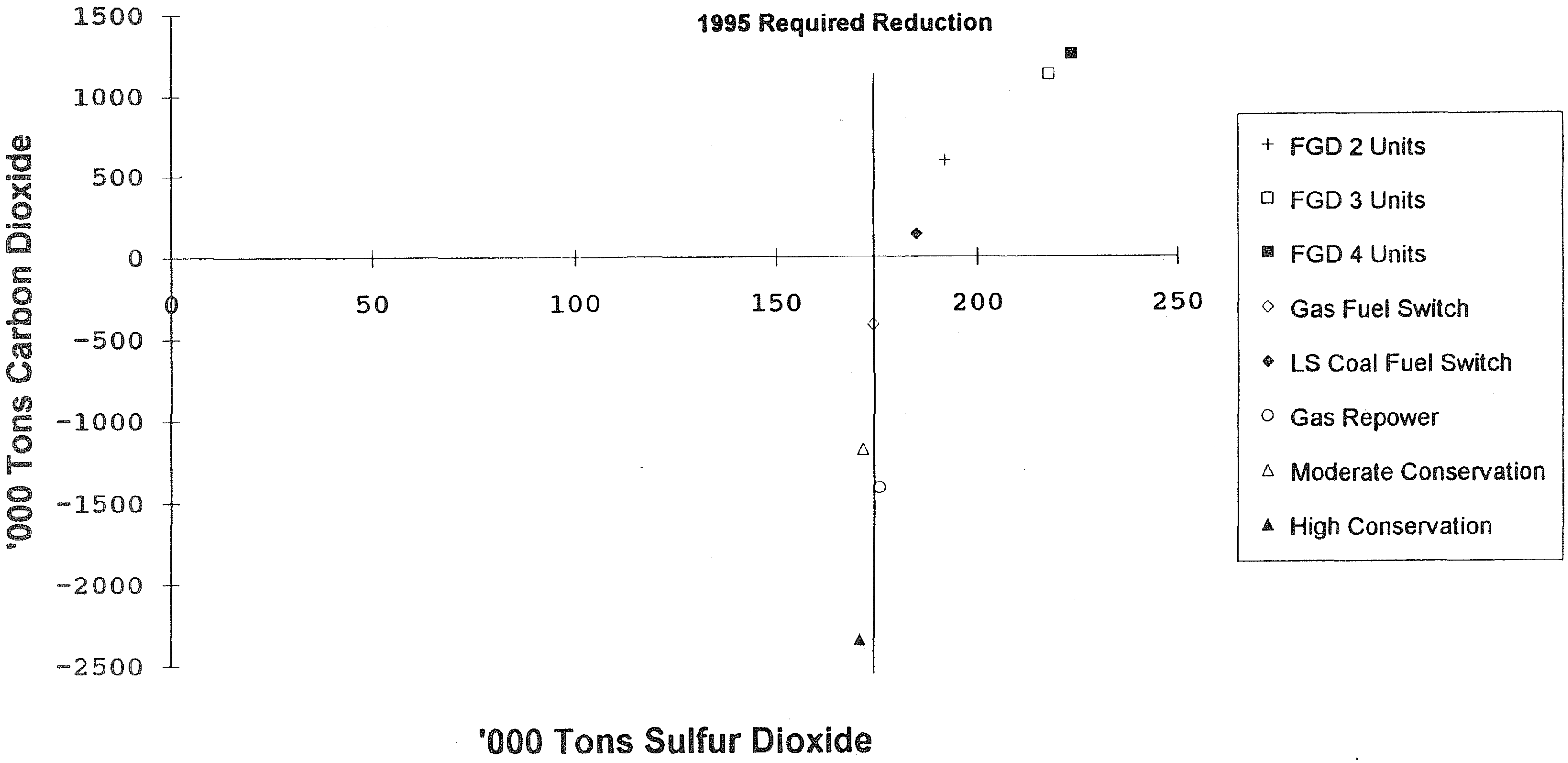

Fig. 1. SO_2 reductions and CO_2 emissions. (Source: Authors' construct.)

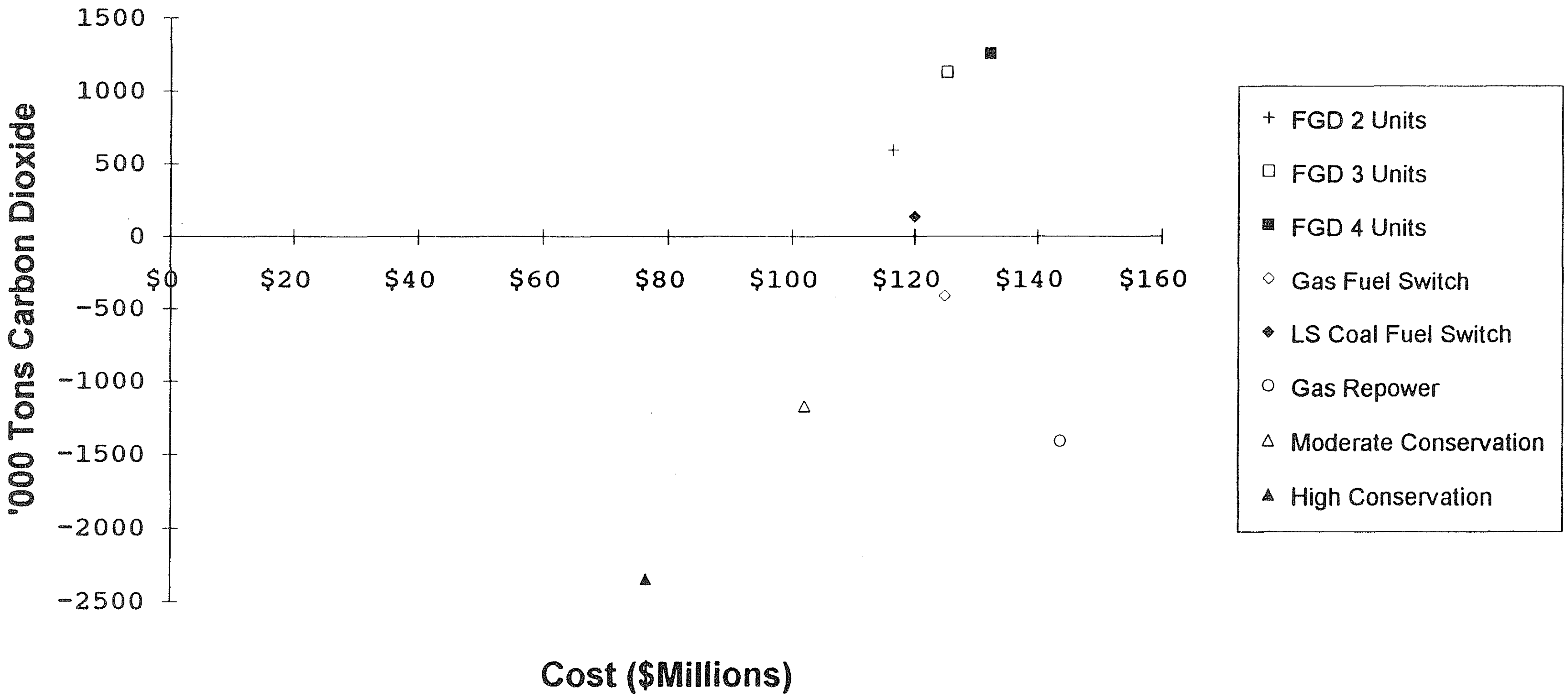

Fig. 2. Annualized compliance cost and CO_2 emissions. (Source: Authors' construct.)

costs from roughly $80 million to $140 million per year. Both conservation strategies offer lower costs and lower CO_2 emissions. In this analysis, conservation not only offers SO_2 reductions at lower costs than other strategies but also provides "free" CO_2 reductions. Gas fuel switching and gas repowering offer lower CO_2 emissions, but tend to be slightly higher priced than the compliance strategies of coal fuel switching and one scrubber. Low-sulfur coal is the most "CO_2 neutral" with the assumption that the heat rate is unchanged, but the heating value of low-sulfur coal is slightly less than that of high-sulfur coal.

At state and national levels the possibility of a tax on CO_2 or the carbon content of fuels has been discussed. IRCP would then have to consider the economic implications associated with carbon emissions. Figure 3 shows a screening curve of the SO_2 removal costs (dollars per ton SO_2) against different levels of a "tax" on the utility's CO_2 emissions.[26] For each compliance strategy, there is a different CO_2 penalty or benefit (see Table 1). The strategies with CO_2 reductions avoid tax payments and lower the cost per ton of SO_2 removed as the tax increases. Strategies such as scrubbers begin to lose their cost advantage over gas fuel switching or repowering because of the CO_2 penalty. At a $20 per ton CO_2 tax (roughly $6 per ton of carbon), gas fuel switching and repowering are preferable to all scrubbing strategies. The CO_2 tax emphasizes again the advantage of conservation strategies which offer lower costs in general, but are significantly lower in cost than all other strategies with the tax advantage.

When the transfer of allowances between utilities is considered, the systemwide (multiutility) CO_2 effects may change. Consider the following example: utility A reduces SO_2 emissions by switching to low-sulfur coal, with essentially no change in its CO_2 emissions. Utility A overcomplies and sells its excess allowances. An allowance purchase then makes it possible for utility B to delay its SO_2 reduction strategy, and continue burning coal. If utility B had planned to repower with gas or use aggressive

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[26] The corresponding carbon (C) tax is the CO_2 tax multiplied by 12/44 (the molecular weight ratio of C to CO_2). Thus, for example, an $11 per ton CO_2 tax is equivalent to a $3 per ton C tax.

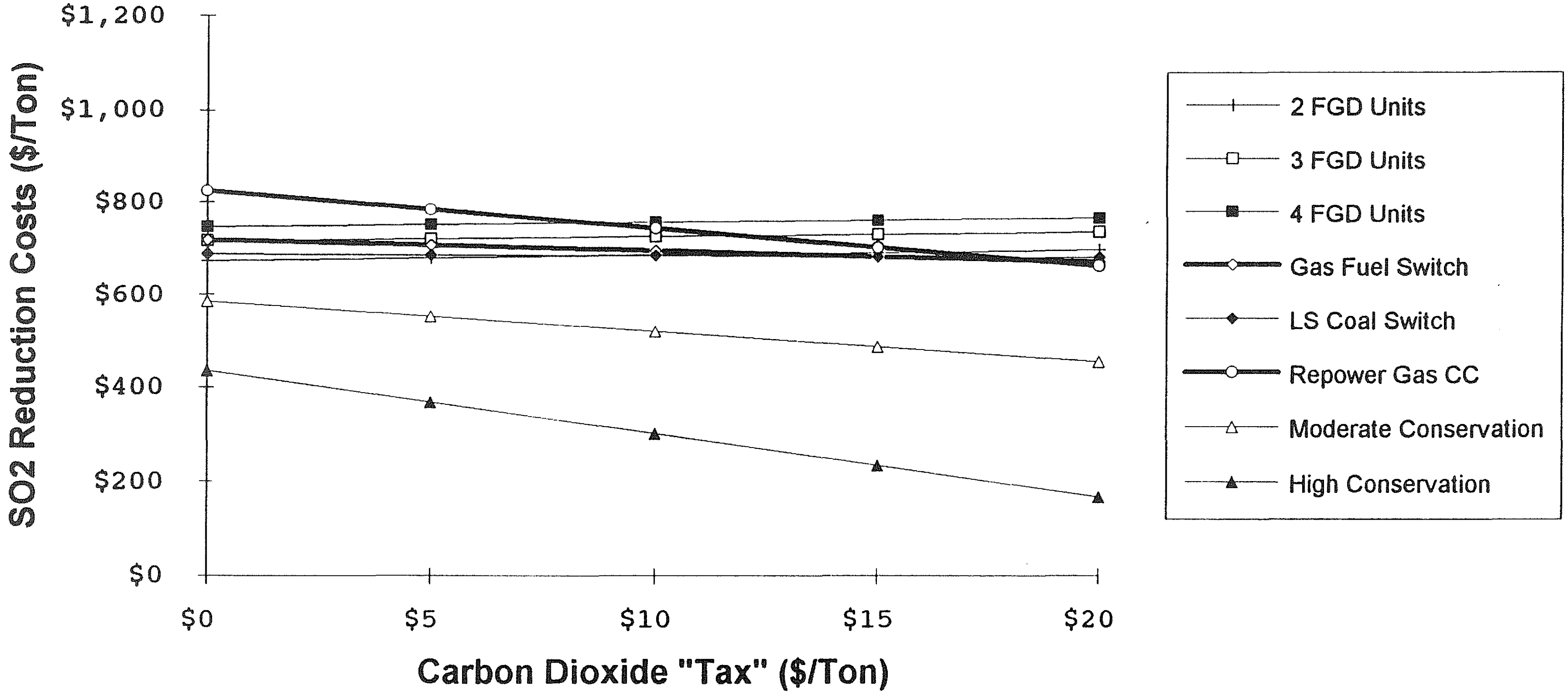

Fig. 3. Compliance strategy costs with utility CO_2 "tax." (Source: Authors' construct.)

TABLE 1

COMPLIANCE COSTS AND CO_2 PENALTY/BONUS

Compliance Scenarios	SO2 Removal Costs Utility (a) $/Ton	SO2 Removal Costs System (b) $/Ton	Ton CO2 Increase per Ton SO2 Reduced Utility (c)	Ton CO2 Increase per Ton SO2 Reduced System Maximum (d)
2 FGD Units	$672	$607	1.16	5.58
3 FGD Units	$716	$575	0.97	11.78
4 FGD Units	$747	$591	0.98	13.20
Gas Fuel Switch	$717	$716	-2.40	-2.34
LS Coal Switch	$687	$649	-0.39	2.01
Repower Gas CC	$825	$818	-8.25	-7.89
Moderate Conservation	$585	$594	-6.56	-7.00
High Conservation	$435	$447	-13.36	-13.84

Notes:

(a) Utility SO2 removal costs equal the 1995 annual cost of compliance divided by the reduction in SO2 emissions for the utility.

(b) System SO2 removal costs equal the 1995 annual cost of compliance plus the cost of allowances, divided by the 1995 required SO2 reductions for the utility.

If the utility makes greater SO2 reductions than required the excess allowances are sold at $700 per ton.

If the utility requires more allowances to comply, the necessary allowances are purchased at $700/ton.

(c) The utility ratio divides the incremental tons of utility CO2 emissions due to the compliance (positive or negative value), by the tons of SO2 reduced by the utility (positive value).

(d) The maximum system ratio assumes all sold allowances result in a release of 41.8 tons of CO2, and divides the utility + allowance CO2 emissions by the 1995 required SO2 reductions for the utility.

conservation, both of which would have lowered its CO_2 emissions, the allowance transaction would have resulted in an increase in overall system CO_2 emissions relative to the case where both utilities pursue individual compliance plans. A national carbon tax or emissions cap would bring attention to such allowance transactions, encouraging overall resource/compliance strategies that reduce both SO_2 and CO_2. Figure 4 reiterates the compliance strategy screening curve and includes a "maximum" carbon penalty on the sale of excess emission allowances. That is, the compliance costs in Figure 4 assume that all excess emission allowances are sold and result in the combustion of coal that would have been displaced by conservation in the absence of the sale. Thus, each ton of SO_2 reduced beyond the compliance level has a forty-two-ton CO_2 penalty on its allowance sale, making compliance strategies utilizing natural gas and conservation economically favorable at lower tax levels than in Figure 3.

This example illustrates the potential for increased CO_2 emissions that may result from a compliance strategy. Ignoring these emissions could result in considerable costs to society due to their potential environmental effects from global climate change. Utilities can and should decrease the risk of incurring these costs by incorporating environmental externalities in the process of developing IRCP.

Conclusion

The implementation of IRP must include compliance planning review, and address the environmental externalities of electricity generation. The SO_2/CO_2 tradeoff between CAAA compliance options illustrates the necessity to incorporate environmental externalities during an IRCP process to achieve both economic least-cost objectives and environmental goals. As regulations advance to achieve additional environmental goals (for example, adopting a carbon tax to stabilize emissions), IRCPs will be best situated to meet those goals at lower costs if planners anticipate and incorporate externalities now. Similarly, policymakers should consider the system effects of the CAAA on important unregulated pollutants such as CO_2, and accelerate efforts to establish IRCP with externalities on a nationwide basis.

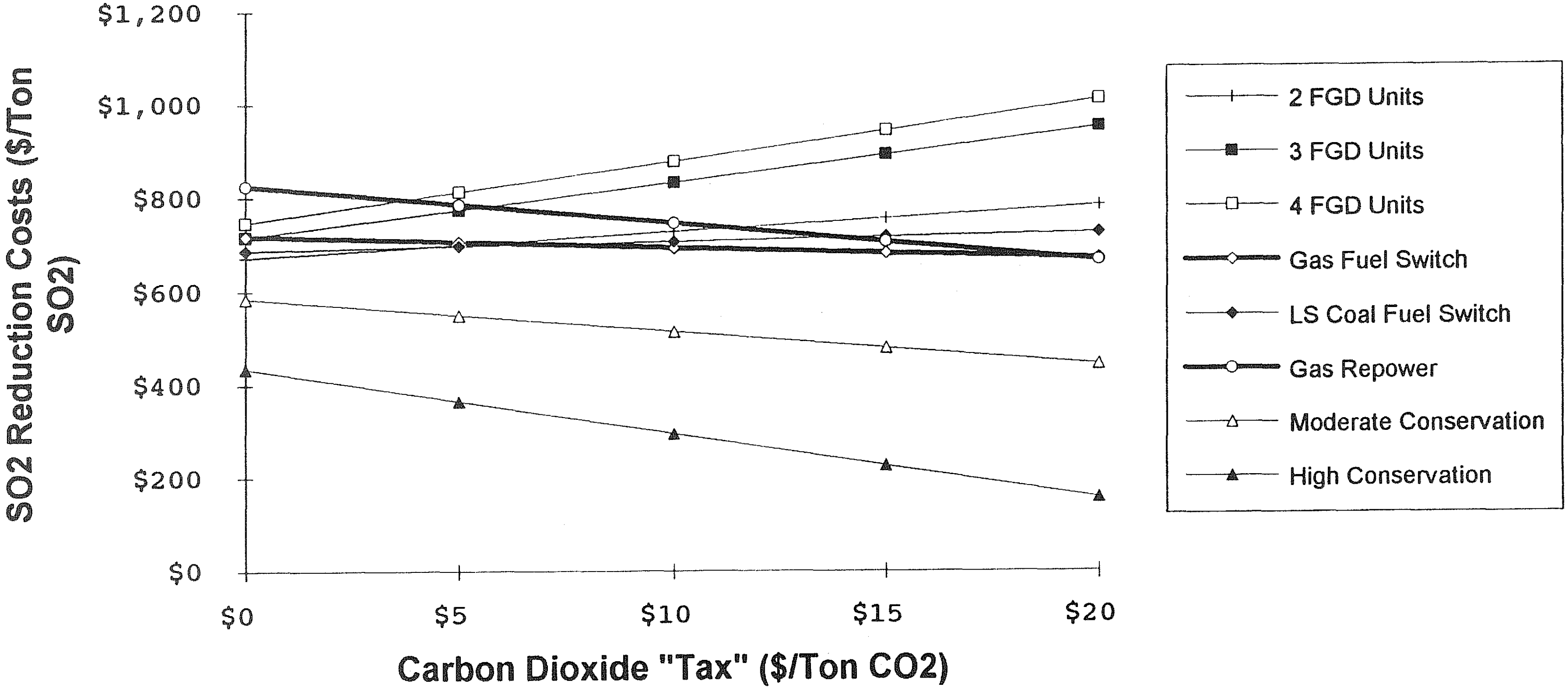

Fig. 4. Compliance strategy costs with "system" CO_2 "tax." (Source: Authors' construct.)

Session III:

Ratemaking Treatment of Allowances and Compliance Costs

- Regulatory Treatment of Allowances and Compliance Costs: What's Good for Ratepayers, Utilities, and the Allowance Market? Kenneth Rose

- Utility Regulators and the Market for Emission Allowances, Douglas R. Bohi

- Discussion Paper on Wholesale Ratemaking Considerations for Sulfur Dioxide Emissions Allowance Trading, Eliot Wessler

REGULATORY TREATMENT OF ALLOWANCES AND COMPLIANCE COSTS

What's Good for Ratepayers, Utilities, and the Allowance Market?

by

Kenneth Rose[1]

Title IV, "Acid Deposition Control," of the Clean Air Act Amendments of 1990 (CAAA) established a national emission allowance trading system. The allowance trading system is a market-based form of environmental regulation designed to reduce and limit sulfur dioxide (SO_2) emissions. This represents a significant departure from traditional forms of environmental regulation which previously consisted of "command-and-control" mechanisms rather that market-based approaches. The argument for a market-based system is that it will result in a lower cost of compliance than a command-and-control mechanism for the same level of emission control.[2]

The allowance trading system, however, is being primarily applied to an economically regulated electric utility industry. The combining of this new form of environmental regulation with the economic regulation of electric utilities, which is also undergoing many changes, has raised the questions: What should be the role of the

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[1] Kenneth Rose is a Senior Institute Economist at The National Regulatory Research Institute (NRRI) in Columbus, Ohio. The views and opinions of the author do not necessarily state or reflect the views, opinions, or policies of NRRI, the U.S. Environmental Protection Agency (EPA), the U.S. Department of Energy (DOE), the National Association of Regulatory Utility Commissioners (NARUC), or its funding commissions.

[2] The first version of the "marketable permit" argument is found in A. C. Pigou, *The Economics of Welfare*, 4th edition (London: MacMillan and Co., 1932). A more recent version is W. David Montgomery, "Markets in Licenses and Efficient Pollution Control Programs," *Journal of Economic Theory* (1972): 395-418.

federal and state commissions that regulate electric utilities? What effect will their actions have on the decisionmaking process of their jurisdictional utilities and the allowance market?

There are different views as to whether significant changes are needed in the way state and federal public utility commissions currently regulate utilities for implementation of the CAAA. One view is that existing regulatory mechanisms, such as least-cost/integrated resource planning (IRP), prudence reviews, fuel adjustment clauses, and ratebase/rate-of-return cost recovery, are adequate for utilities to implement the requirements of the CAAA. Although some modification of these regulatory mechanisms may be necessary to accommodate allowances, this view maintains that the CAAA does not present any new challenges or opportunities for commissions.

In this view, these current rules and procedures provide sufficient incentives to utilities to control their compliance costs and cope with allowances and any required risk allocation. Also, there may be unintended negative consequences from too radical a change. Finally, since considerable cost savings can be obtained 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.

A contrasting view is that some changes are required to current regulatory practices if the full potential of the allowance system is to be realized. This is because the allowance system and the choice of options now available to utilities, provides utilities an opportunity to significantly lower compliance costs than what would have occurred with command-and-control environmental regulation. However, there may be little incentive to use the allowance market and minimize compliance costs with traditional ratemaking methods. As a result, it is less likely that an efficient allowance market will emerge without some regulatory changes. In this view, commissions should be concerned with the national allowance market since ratepayers can receive additional benefits from its successful development.

Thus, not considering policy changes that assist the development of an efficient national allowance market and ignoring its potential benefit to ratepayers is shortsighted. The challenge for commissions, both the state public utility commissions and the Federal

Energy Regulatory Commission (FERC), is to develop regulatory procedures that dovetail with the national allowance system created by the CAAA. One possible procedure, using a market-based approach, is presented below.

Thus far, two years after the CAAA's enactment, commissions are finding that their own decisions are having an effect on the market. Because of the more than expected overcontrol (that is, overcompliance with the CAAA requirements) for phase I compliance and for other possible reasons,[3] the forecasted price of allowances has fallen considerably.[4] Utilities, in general, have adopted go-it-alone strategies and few utilities have considered allowances as an option (either buying or selling[5]). If this trend continues, then the failure of the market may become a self-fulfilling prophecy. The irony is that in order to have this market-oriented system work and realize at least some of the projected cost savings, it will have to be relied on to a greater extent. However, utilities have indicated a reluctance to use the market because of the uncertainty of its success. Unless a commitment to use the market is made by utilities and commissions, it probably will not develop to its fullest potential.

There are several dimensions to the regulatory problems that commissions face. Allowances and utility compliance expenditures have implications for least-cost/IRP,

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[3] One of the other reasons given for the fall of allowance prices is the bad publicity in the national media that followed the first two trades. Some utilities have maintained that this will make them more reluctant to participate in the allowance market in the future. Another reason given is the lack of regulatory guidance to utilities from the public utility commissions. It is not clear, however, if either of these has actually had a significant effect on the market.

[4] When the CAAA passed in late 1990, it was expected that allowances would sell in the $650 to $750 range. Recent trades, however, have been in the $200 to $250 range. In the first annual EPA auction, held in March 1993, the lowest price for 1995 allowances was $131.

[5] As of this writing, there have been approximately one-half dozen publicly announced allowance transactions and there have been reports of other private trades.

prudence review procedures, holding company and multistate utility regulation, and ratemaking treatment. The focus of this paper is on the ratemaking treatment.[6]

Ratemaking Treatment of Allowances and Compliance Costs

Of particular concern to many in the industry is the ratemaking treatment of allowances and compliance costs. This includes such questions as: Which utility compliance investments should be placed in rate base? How should the sale and purchase of allowances, including any gain or loss, be treated for ratemaking purposes? Who should assume the risk of allowance price changes? Possible ratemaking treatments of allowances and compliance costs by commissions can be grouped into three general categories. The first is applying "traditional" mechanisms to the problem of CAAA implementation. Although allowances have no exact analogy, existing regulatory mechanisms to deal with determining a rate base, fuel inventory, operating expenses, and planning for future requirements, can be adapted. However, as will be discussed later, there may be some significant drawbacks to this approach.

A second ratemaking treatment recognizes that traditional methods may have some limitations when applied to implementing the CAAA. Moreover, these traditional methods are currently under reevaluation themselves due to, among other reasons, the lack of the incentive given to utilities to minimize their operating costs.[7] In response, regulators in the United States and abroad have increasingly turned to incentive- or market-based mechanisms, such as price caps, performance incentives, and competitive bidding, to avoid the limitations thought to occur with traditional regulation. A market-

[6] These other topics are covered in Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, May 1992).

[7] Five often-cited limitations to traditional ratebase/rate-of-return regulation are reviewed in Kenneth Rose, "Price-Cap Regulation: Some Implementation Issues," *NRRI Quarterly Bulletin*, 12, no. 4 (December 1991).

based ratemaking treatment of this general type can also be developed for allowances and compliance cost.

This method is also consistent with utilities becoming increasingly fragmented into competitive and noncompetitive segments. This fragmentation in the electric industry (and other regulated industries as well) has led regulators to adopt different regulatory procedures to take advantage of competitive markets when available. These competitive markets may arise because of technological advances, such as with the telecommunications industry, or because of legislative or regulatory changes, such as with natural gas production and distribution and the Energy Policy Act of 1992. The market-based allowance trading system provides such an opportunity from the CAAA's legislative initiative with a large potential benefit for utility ratepayers. However, economic regulatory changes may also be needed to take full advantage of this potential.

A third ratemaking treatment can be developed where the compliance activities of the utility are separated or unbundled from the regulated functions. This method also recognizes that the industry trend is moving toward greater levels of competition and that increasing components of the firm (primarily generation and transmission) are either being deregulated or regulated less.

It is important to consider that all possible ratemaking treatments will have a profound effect on a utility's choice of compliance option and, ultimately, the cost to ratepayers. The CAAA's allowance trading system represents a significant departure from command-and-control environmental regulation. Commissions and utilities can either view it as an obstacle to be overcome or as an opportunity to achieve the environmental goals established by Congress in the CAAA at a lower cost than traditional command-and-control. At stake is the predicted $1 billion to $3 billion annual savings[8] from having an allowance trading system rather than a command-and-control system.

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[8] Paul R. Portney, "Policy Watch: Economics and the Clean Air Act," *Journal of Economic Perspectives*, 4, no. 4 (1990): 173-81.

Each of these three ratemaking methods are discussed below, including the advantages and disadvantages with respect to the effect on ratepayers, the utility's incentives, and the allowance market.

Traditional Cost-Recovery Mechanisms

In general, pollution control equipment has in the past received favorable rate treatment, that is, these investments have usually been included in the rate base. Many states also allowed construction work in progress (CWIP) and accelerated depreciation for pollution abatement equipment. Some states have CWIP for pollution control investments that do not have CWIP for other types of capital investments.

The reason for the favorable treatment is that pollution control investments were a federal or state mandate. It is unlikely, however, that this favorable rate treatment will continue given the discretion utilities now have to comply with the SO_2 requirements. Under the CAAA, utilities can choose (with some limitations[9]) the technology or compliance option to use, such as scrubbing, fuel switching, repowering a unit, and purchasing allowances. Commissions are currently (mostly for phase I utilities) reviewing plans submitted by utilities and, in general, have indicated that a range of options should be considered.[10]

As noted, allowances are a new regulatory instrument having no existing regulatory rules or procedures for commissions to apply from previous experience.

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[9] Although a utility has a great deal of discretion in choosing how to comply with the SO_2 requirement of Title IV of the CAAA, utilities' emissions are also limited by Title I, the National Ambient Air Quality Standards (NAAQS), and Title III, Hazardous Air Pollutants.

[10] Several state legislatures, in the interest of protecting in-state coal production, have intentionally limited the choice of options. For a state-by-state summary of twenty-eight states' compliance actions (nineteen of the twenty-one phase I states are included) see, Kenneth Rose and Robert E. Burns, *Regulatory Policy Issues and the Clean Air Act: An Interim Report on the State Implementation Workshops* (Columbus, OH: The National Regulatory Research Institute, 1992).

However, existing regulatory procedures are flexible enough that they can be adapted to accommodate allowances and costs associated with CAAA compliance. This first ratemaking treatment of allowances is based on how commissions have dealt with similar issues and analogous assets. Commissions are likely to draw upon these previous experiences when establishing a policy for allowances. For example, commissions have often dealt with the treatment of gains and losses of land held for future use. In those cases, the regulatory treatment of gains and losses was determined by the source of funding for the sold asset. In the case of allowances, an argument can be made that ratebased assets are the source of the initial allowances because these allowances reflect the past emissions of a particular unit necessary to meet the utility's customer demand during the base-line period. Of course, others would argue that since the utility assumed the risk when building these plants (and in some cases did not earn a return on the investment until the plant was completed and selling power to ratepayers) the utility should share at least a portion of any gains or losses.

Under this regulatory approach, prudent investments in capital equipment, such as scrubbers and plant modification for fuel switching, would be added to the rate base. Any revenue from the sale of allowances "freed-up" because of a ratebased investment may, under this approach, be deducted from the asset value in the rate base. For example, if the compliance strategy involved a scrubber and if the investment is included in the utility's rate base, then the proceeds from the sale of allowances freed due to overcompliance would offset the cost of the scrubber in rate base. This is because ratepayers, in effect, provide the source of funding for the pollution abatement facilities by providing a return on the utility's prudent investment in those facilities. Any additional return to the utility from the facilities should benefit the ratepayers through a deduction from the utility's rate base of the gains from the sale of allowances. A commission could maintain this regulatory approach until the utility's pollution control facilities in rate base become zero.

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 and these higher costs passed through an existing fuel adjustment clause (FAC). Since purchased allowances are "used up" along with the fossil fuel (or stored or "banked") for future use, used allowances may analogously 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 would have to guard against unnecessary banking of allowances, that is, the utility holding too many allowances when there is an opportunity to economically sell them; particularly if allowance costs are allowed in rate base. This would be similar to what commissions currently do with fuel inventory. There probably already is a strong incentive to hold an adequate number of allowances. This is because 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.

Determining whether there was a gain or loss on the sale or purchase of allowances may be difficult for commissions to ascertain given the choice utilities now have on how to comply. Commissions may not care to become involved in the appropriateness of the price of an individual allowance for each transaction. Allowances may be bought and sold many times over the course of a year, the accounting alone could become quite burdensome. Commissions may consider, therefore, more general measures of allowance inventory for ratemaking purposes that indicate the general effectiveness of the utility's allowance procurement practices. Traditionally, as is often the case with fuel procurement, this would be done in a prudence review.

The difficulty with this approach is that now utilities can be either purchasers or sellers of allowances. For this reason, commissions may be tempted to compare the cost of reducing a ton of emissions with the market price. For example, if a utility built a scrubber where the cost was $600 per ton but allowances could be purchased for $450, the commission may consider a disallowance of $150. A similar comparison could be made with allowances purchased in previous years. The limitation to this method is apparent, however, when it is considered that the price of allowances is likely to vary from year to year, and that after-the-fact punitive measures may not encourage good planning and execution of a plan by a utility. Other means of determining the appropriateness of compliance actions need to be explored.

Limitations to the Traditional Approach

As noted, any ratemaking approach will have a profound effect on the decisionmaking process of a utility and may bias, perhaps unintentionally, the utility's investment decisions. A traditional ratemaking treatment may introduce an unintended bias in favor of compliance options that are not necessarily the lowest cost solution. 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.[11] 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 actions (such as purchasing fuel) and foregoing more capital-intensive (and more uncertain) options which may have long-term benefits to the utility and its ratepayers.

Under certain conditions (primarily when the rate of return exceeds the cost of capital), a bias toward large capital expenditures is possible. In addition, if the initial allowances earn no return but the commission states up front that large capital expenditures for compliance, such as scrubbers, will be ratebased, a great deal of the uncertainty associated with that decision (whether it will be ratebased) is removed. All state commissions except one (with few jurisdictional generating facilities) allow pollution abatement investment into rate base.

Therefore, if there is a virtual guarantee that the investment will be ratebased, that initial allowances will not be, and that the sale of any allowances will be used to

[11] For further discussion of this point, see, Rose, *Public Utility Commission Implementation*, specifically Chapters 3, 7, and 9. Also see, Douglas R. Bohi and Dallas Burtraw, "Utility Investment Behavior and the Emission Trading Market," *Resources and Energy*, 14 (1992): 129-53.

deduct the value of the pollution control asset, then the profit maximizing firm will tend toward large capital investments and will sell or bank excess allowances. The decision on how many to sell and convert to cash and how many to bank will depend, in part, on the utility's rate of return on capital and the anticipated reaction from the commission to the utility's decision. Ideally, the utility would base its sell/bank decision on its forecast of its own future need and expected future cost of allowances and fuels and not on a distortion created by the ratemaking treatment.

Another example is the unintended bias that could arise from an FAC that could bias the utility toward a fuel-switching option. If future cost increases in low-sulfur coal are allowed to be passed through to ratepayers, then utilities may favor fuel switching (to low-sulfur coal), even though this is not necessarily the lowest cost option.[12]

Careful attention should be given to the incentives the utility receives from the ratemaking process. In general, traditional methods could foster a "go-it-alone" strategy of overcontrol by the utility since it cannot benefit, or may even be harmed, by using the allowance system as originally intended (an example is given in the next section of how the trading system is ideally supposed to work[13]). An incentive-based ratemaking system, in contrast, can be designed to give the utility an incentive to adopt a compliance strategy that is in the ratepayers' interest by allowing the utility to benefit from its good decisions but still be held accountable for faulty ones.

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[12] For a general discussion of the limitations of FACs see Chapter 5 "Fuel Adjustment in a More Open Market Environment," in Robert E. Burns, Mark Eifert, and Peter A. Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, 1991).

[13] For a description of the original theoretical use of a trading system, see T. H. Tietenberg, *Emissions Trading: An Exercise in Reforming Pollution Policy* (Washington, D.C.: Resources for the Future, Inc., 1985). For a summary of this see, Rose, *Public Utility Commission Implementation*, Chapter 3.

Traditional Approach and the Allowance Trading Market

A traditional approach may also have a negative effect on the overall national allowance market. This can be illustrated with a simple example of the benefits from trading as presented in Figure 1. This example uses a single hypothetical marginal-cost structure and different reduction requirements for two firms. In this example, two utilities, firm A and firm B, have CAAA affected units requiring a 300-ton and a 50-ton SO_2 emission reduction, respectively. Both firms may have an endowment or allocation of allowances from the environmental regulator (EPA), however, for both firms the original allocation of allowance is insufficient to cover the firm's current emissions. Figure 1 depicts the reduction in SO_2 emissions required by the CAAA beyond their respective allocation of allowances.

Only two firms are shown in this example, however, other firms exist. All affected firms together (there will be over 2,700 units affected by phase II) determine the market price of allowances. A critical assumption is that these two firms are price takers, that is, their actions alone are insufficient to affect the market price.

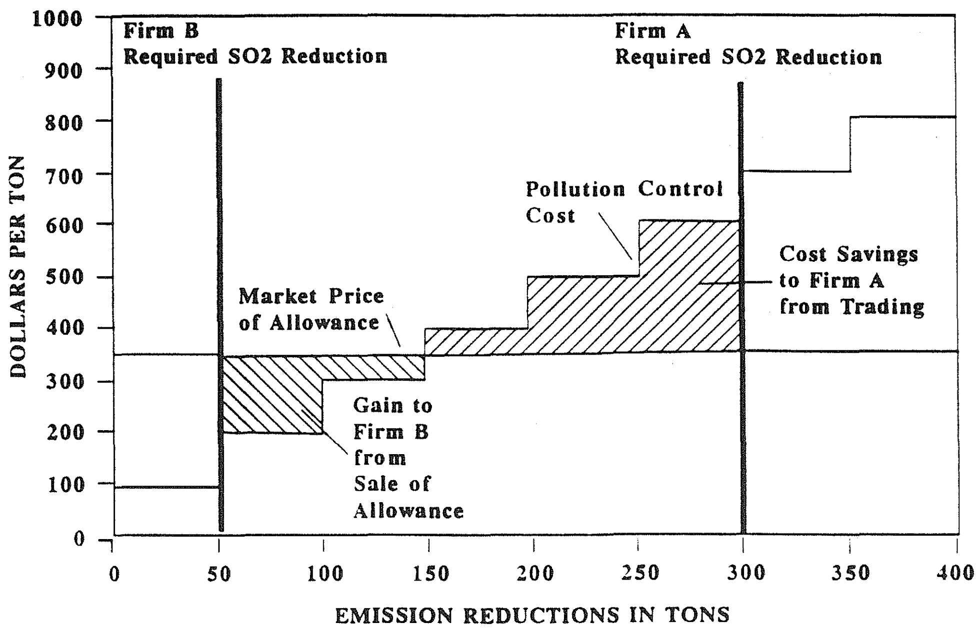

Fig. 1. Potential benefits of allowance trading for two hypothetical firms.

Various control options are available to the firms which are characterized as being "lumpy." In this simple example, pollution control options can reduce emissions in blocks of fifty tons with increasing incremental or marginal cost of control. To eliminate the first fifty tons of emissions requires a cost of $100 a ton with the first pollution control device. The next fifty tons of emission reductions will cost $200 a ton. To eliminate the next fifty, $300 a ton, and so on. The main point is that pollution control is incrementally more expensive. It can now be used to show how, through allowance trading, the utility can minimize the cost of pollution control and still meet the required reduction in emissions.

Firm A characterizes a buyer of allowances in this example. If the firm were to incur the entire cost of reducing its emissions by the required 300 tons, the total cost would be $105,000 ($5,000 + $10,000 + $15,000 +. . .+ $30,000) for the first six lowest cost control options. Suppose that the market price for an emission allowance is $350. For the first 150 tons of emission reductions the firm will choose the first three (lowest incremental cost) pollution control options for a total cost of $30,000 ($5,000 + $10,000 + $15,000). The next 150 tons, using allowances, will cost $52,500 (150 x $350), for a total cost of $82,500. The firm saved $22,500 by reducing the first 150 tons itself and purchasing allowances for the next 150 tons. The available technology would have required an additional $75,000, but the requirement was met with an expenditure of $52,500 for allowances instead.

Firm B in Figure 1 characterizes a seller of allowances who is required to reduce its emissions by fifty tons. In this case the firm can meet all of its required reduction with its first control option at $100 a ton for a total compliance cost of $5,000; no purchase of allowances is required. However, the next two options can be achieved for less than the price of allowances. If the firm were to reduce its emissions by 150 tons for a total cost of $30,000, the firm would "free-up" 100 allowances that, if sold, would be worth $35,000 ($350 x 100). The last 100 allowances cost the firm $25,000 to produce, for a net gain of $10,000. Since it cost the firm $5,000 to reduce the first fifty tons, the gain on the sale offsets this cost with $5,000 remaining.

It was assumed here (for the sake of clarity) that both firms had the same control costs. What varied in this example was the required emission reduction. In reality, of course, firms face different control costs, and this too could cause different firm behavior even with the same reduction requirement. Note also, that a sufficiently high allowance price, above $700 in this example, would change firm A from a buyer to a seller of allowances.

Traditional regulatory methods can induce a firm to realize the area, "cost savings to firm A from trading." This is because, after an investment or expenditure has been made, a firm that incurs control costs above the then current price of allowances faces the possibility of a disallowance in a prudence review. If the price could not be anticipated, then, to avoid such a disallowance, the utility must be able to justify a reason why it was beyond its control to predict. Or, before the investment or expenditure is made, a utility may be dissuaded from pursuing these options because they are not likely to be considered "least-cost" in a least-cost/IRP process. This, of course, ignores intentional biases, such as for in-state coal, and assumes the planning process itself is not flawed in some way.

Note, however, that firm B in this example faces a different decision. To comply with the CAAA, all firm B has to do is reduce emissions by fifty tons; incurring the $100-a-ton cost which is well below the price of allowances. If the revenue from selling allowances is not considered, then this appears to be the least-cost solution. However, even if the value of allowances is considered, the area, "gain to firm B from sale of allowances," would most likely, as described above with traditional regulation, be entirely passed through to ratepayers. As a result, there is little or no incentive to overcontrol and sell allowances.[14]

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[14] Another possibility is that the firm could incur the cost of reducing emissions by the extra 100 tons and then not be allowed to recover that additional cost because it was judged to be unnecessary in a prudence review. Note that *if* the firm were able to retain the gain on the sale of allowances, it would still make economic sense to overcontrol since the firm would be better off. It is unlikely, however, that a commission would disallow these costs *and* deny the profit from the sale of "extra" allowances.

In order to function efficiently the allowance market requires that all firms be sent the correct economic signals. The allowance market, as with any market, requires not only that there is no uneconomic production (overcontrol of facilities to free-up allowances), but also that potential sellers of allowances are given an incentive to economically produce allowances. This leads directly to the second type of regulatory treatment that is designed to send the correct economic signal to utilities.

Market-Based Cost Recovery Mechanisms

An alternative to these and other traditional approaches are market-based or incentive-type mechanisms. By one survey, about thirty states now use some type of incentive mechanism for electric utility regulation.[15] These mechanisms include incentives to achieve socially desirable goals, such as investment in demand-side management (DSM) projects and incentives to minimize operating costs (thought to be insufficient with cost-plus regulation) such as power plant performance or benchmark standards.

There is evidence that utilities respond positively to these incentive mechanisms. For example, the over 1,300 individual DSM programs nationwide can largely be attributed to the recent increased use of incentives by commissions to encourage utilities to adopt DSM measures.[16] Also, there is some evidence to suggest that the use of price-cap regulation in the telecommunications industry has resulted in significantly lower

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[15] National Economic Research Associates, Inc., *Incentive Regulation in the Electric Utility Industry* (Washington, D.C.: National Economic Research Associates, 1990).

[16] RCG/Hagler, Bailly, Inc., "Comments on Incentives for Purchases of Nonutility Generated Power," in the *Proceeding to Consider the Reauthorization of the Texas Public Utilities Commission*, Sunset Review Commission of Texas, June 1992.

customer prices.[17] Although market-based mechanisms can be designed within a traditional regulatory structure, they do require some departure from stringent cost-plus or ratebase regulation.

An incentive or market-based mechanism can be developed to encourage utilities to minimize their SO_2 control costs. The primary advantage that a market-based mechanism has over a traditional method is that it provides the utility with more incentive to be cost efficient.[18] This includes reducing the utility's operating and capital costs through improved efficiency, as well as allowance purchases and sales. An incentive-based mechanism would reward a utility in the long run for good performance within its control (that is also in the interest of ratepayers) and penalize it for bad performance within its control. This increases the utility's motivation for adopting innovative and cost-effective approaches when developing a compliance strategy.

An incentive mechanism for SO_2 control costs could consist of the commission setting a benchmark value for allowances, similar to a price cap, that the utility's actual control cost could then be measured against. If the utility is able to outperform this 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) or as a "loss" (the difference between the benchmark and control cost when the control cost is higher).

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[17] Mathios and Rogers found, in an econometric analysis comparing long-distance telephone service in states that allow pricing flexibility (price caps) with states that do not, evidence that suggests rates were significantly lower in states that allow price flexibility than in states that use rate-of-return regulation. See, Alan D. Mathios and Robert P. Rogers, "The Impact of Alternative Forms of State Regulation of AT&T on Direct-Dial, Long-Distance Telephone Rates," *Rand Journal of Economics*, 20, no. 3 (Autumn 1989): 437-53.

[18] For a discussion on this point and analysis of different types of incentive mechanisms, see, Paul L. Joskow and Richard Schmalensee, "Incentive Regulation For Electric Utilities," *Yale Journal on Regulation*, 4, no. 1 (Fall 1986).

The benchmark can be posted in advance and the utility given reasonable assurances that it will be applied objectively. The benchmark could be set and adjusted annually at the beginning of the year during, for example, EPA's true-up period. At the end of the year or some other period, the difference would be calculated and future rates adjusted accordingly. (Alternatively, the commission could set the benchmark periodically and, rather than track the control cost, simply use it as the basis for the utility's compliance cost recovery. This option is discussed below.)

Under this approach, the commission does not prescribe or approve the specific control technology planned or used by the utility. The utility's reward is based on its own control cost and the price of allowances, a factor external to the firm and beyond its control. As a result, the lower it is able to reduce its control costs (below the market price), the greater its reward. This increases the incentive to reduce costs by adopting or developing innovative technologies and operating in an efficient manner.

Methods of Determining the Benchmark

The benchmark can be set in one of at least three ways utilizing: (1) the utility's expected control cost, (2) an estimated value of allowances, or, eventually when more market information is available, (3) the market price of allowances. Each method, of course, has its own advantages and disadvantages.

The first method, which uses the utility's control cost, would have the commission determine the utility's expected control cost for a given period (for example, one year). At the end of that period the actual control cost would be determined and the difference calculated, as outlined above. An advantage of this first method is that the utility's control cost is, in general, a readily available number. For this reason this may be the simplest method of the three to implement. There are, however, two significant drawbacks to this method.

First, it is likely that the benchmark may be set too low or too high relative to the market price of allowances, since it is unlikely that the utility's marginal control cost is just equal to the market price of allowances. If the benchmark is set too high, it may encourage the utility to invest in more pollution control than is cost-effective (relative to purchasing allowances, see Figure 1). Conversely, if the benchmark is set too low, not enough investment in pollution control will be made and perhaps an opportunity to sell allowances (that is, cost effectively reduce overall compliance costs) may be missed. Secondly, because the utility has considerably more information concerning its system operations, there is a chance the utility will "game" the numbers it submits to the commission. That is, there may be an incentive for the utility to overstate its expected control cost in the belief that it will be able to easily beat the benchmark and be rewarded with little chance of detection by the commission. This gives the utility a justification to, for example, invest in pollution control technology beyond what would be considered economic.

The second method of setting the benchmark, estimating or forecasting an allowance value, would have the commission, the utility, or both, forecast the market price of allowances. This would have the advantage of avoiding the gaming of the expected control cost by the utility (but not avoiding other types of gaming) since the benchmark would be based on external factors beyond its control. An obvious drawback, of course, is that forecasting methods themselves are imperfect. Utilities may tend to favor forecasting methods that have an upward bias (justifying more pollution control investment) while interveners for consumers may favor methods that have a downward bias (in the hope of keeping costs down). Also, this method could place a burden on existing commission staff or require new qualified staff to be hired, particularly relatively smaller commissions.

The third method would use the current market price of allowances to determine the benchmark. The commission, for example, could calculate this benchmark using a weighted average of current short-term, long-term, and futures contracts similar to how some states determine a fuel price comparison for a prudence review or a cap for fuel or purchased power. The benchmark could be set prospectively by the commission at, for example, the beginning of the year. At the end of the year (or whatever chosen period) the difference could then be calculated between the benchmark and the firm's actual control cost. Commissions could also retrospectively calculate the benchmark at the end of some time period.

The advantage to this third method is that it provides the maximum incentive to the utility to minimize its compliance and emission control operating costs. This is because the incentive is to beat the cost of a risk-minimizing portfolio of allowances (the market price) and is not based on the utility's own internal costs or a forecast. This method, therefore, is the most likely of the three methods to lead to the development of an efficient allowance market.

Consequently, there is a strong incentive for the utility to carefully forecast allowance prices (on its own) and use risk management techniques (such as long-term forward and futures contracts) to manage the firm's risk. If most or all of the risk of an allowance price change is on the ratepayers, as with traditional rate treatments, there is little incentive on the part of the utility to use these risk management techniques. If this risk is placed on the utility, however, it is important that it is allowed to retain a portion of the gain from good decisions. Just as important, the utility must believe that these benefits will be forthcoming and that the process will be conducted consistently and fairly.

A disadvantage to this third method for setting the benchmark is that, there has been insufficient allowance market information to calculate a "market" price. To date, there have been only a few trades made public where price information was made available.

Commissions may want to consider, as a temporary measure at this early stage in the development of the allowance market, the first or second method of setting the benchmark. Modeling techniques to forecast a close approximation of a fair market value or the firm's expected control cost could be used until more allowance market information becomes available. Because of the limitations of the first two methods, it is important that these means be viewed as temporary. As the market develops, a shift to actual market prices could take place. These temporary measures could foster the market's development by encouraging utilities to use the allowance market. This would require, in the beginning, some early cooperation between the commission and its jurisdictional utilities to determine a fair estimate of the market value or to control costs. The long-term benefit to ratepayers of a successful trading system could be worth the risk and effort.

Determining the Split Between Ratepayers and the Utility

Another important consideration is the distribution of the gain or loss the utility incurs. There are several aspects to this determination. First, the utility's portion of either a gain or loss must be sufficiently large in order to encourage the desired cost-minimizing behavior. The reward or penalty must be able to induce the utility to incur the cost of conducting the required planning and management necessary to pursue innovative and cost-effective options. Second, the utility's portion must not be so large that it negates the benefit to ratepayers (for example, larger than the area "gain to firm B" in Figure 1). With current incentive programs, this portion varies considerably with the type of program and is sometimes tied to the firm's rate-of-return. Thus, there is no percentage share or method for determining the share that can be applied in all utility cases. It instead should be based on the situation of the individual utility. For example, a net seller of allowances, such as firm B in Figure 1, may have certain cost advantages that result from previous capital investments that are now in the rate base. In this case it could be argued that the proportion should be relatively small and limited to only encouraging operational efficiency. Conversely, a utility that will need to make substantial investments (in capital or allowances) may require a larger share of any potential gain or loss.

Third, the incentive mechanism itself must be credible and the utility given assurances that the gain or loss will be determined and carried out fairly and according to the commission's prescribed procedure.

Other Regulatory Approaches

As noted, a third regulatory approach can be developed where the compliance activities of the utility are further separated from its regulated functions. This method is specifically designed to coincide with the industry trend toward developing greater levels of competition with increasing components of the firm being either deregulated or regulated less. Two methods of this type of approach are discussed here.

The first method is a modification of the market-based method described above. In this instance the commission sets the benchmark periodically as described above but uses it as the basis for the utility's compliance cost recovery. The commission would not track the utility's control cost or make adjustments based on the share of the gain or loss. In effect, the utility assumes all the gain or loss from its compliance decisions. This results in the risk associated with allowance price and benchmark changes being completely assumed by the utility. The commission simply sets the benchmark and allows the utility to recover the full amount, irrespective of the actual cost incurred by the utility. This is similar to the pure or more academic form of price caps; the commission sets a cap and, in this case, adjusts it periodically as allowance market conditions change.

Ideally, in this case (for reasons mentioned above) the benchmark would be set using allowance market price information. As noted, however, currently there is insufficient market price information available. Given this situation, commissions would probably be reluctant to rely on forecasted prices (as a temporary measure) when there is no adjustment made for the utility/ratepayer share. As a result, this approach may have to wait until more market information is available, perhaps well into phase I or the beginning of phase II of the CAAA.

Another problem arises from allowing all the benefits or losses to be passed on to the utility. As noted earlier, the firm's compliance decisions will depend heavily upon the existing assets of the firm. Some utilities with little or no additional investment will be able to free a large number of allowances. In most cases the assets that make this possible are ratebased, earning a rate of return and being depreciated. For this reason commissions will most likely be reluctant to allow the utility to earn a profit (possibly a substantial one) "below the line," although ratepayers do not benefit directly at all from the ratebased assets.

A second method could find a way around this problem by giving the utility an option of purchasing some or all of the allowances in exchange for less regulation or deregulation of compliance activities, and more discretion in selection of compliance methods and the use of allowances. In effect, the utility would compensate the ratepayers for their beneficial ownership in the allowances. This is determined by the ratebase status of the generating facilities and the utility's fiduciary duty to act in the ratepayers' beneficial interest.[19] For many utilities, however, this could impose a heavy financial burden and, as a practical matter, be difficult to implement.

A limitation of both these methods is that there could be cross-subsidization between the firm's still-regulated portion (retail and wholesale activities) and its deregulated (pollution control) activities. Under such a policy, the utility may attempt to maximize the number of allowances for sale and shift the cost of pollution control to the regulated activities of the utility. This is particularly a problem when it is considered how closely compliance and generating activities are allied. Mitigating this to some extent would be the potential growth in segments of the firm's market making it more competitive. Increasing competition would encourage more cost control in traditionally regulated activities. However, the level of competition sufficient to induce this kind of behavior may be several years away. Once some of the effects of the recent National Energy Policy Act of 1992 have filtered through the industry, this kind of approach may be appropriate.

Limitations of Incentive Mechanisms

Commissions may be limited statutorily in the types of incentives they can provide to jurisdictional utilities. This may occur in three ways. First, suppose a utility is unable

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[19] See, Rose, *Public Utility Commission Implementation*, Chapters 8 and 9.

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, suppose a utility outperforms the benchmark standard set by the commission, and as a result, the utility earns more than its allowed rate of return. There may be a legal requirement (or temptation) 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 particular constituencies in mind, sometimes independent of the cost to ratepayers. Placing a regulatory incentive mechanism on top of this type of mandate would seem to be impractical because it is unlikely that commissions could justify passing through costs to ratepayers and then allow an incentive for the utility. If, for example, there was a gain from the mandated compliance action, it most likely would simply be passed through to ratepayers.

As a result of these statutory limitations in some states, legislative changes may have to occur before an incentive mechanism of the type discussed above could be initiated.

Conclusion

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 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.

If an incentives approach is chosen by a commission, it should be recognized that one of its requirements is that the level of the commission's involvement in the planning process should be kept to a minimum. The incentives approach is designed to prompt the utility to minimize its compliance cost without explicit direction on *how* to comply from the commission. It would be inconsistent with this approach for the commission to become directly involved in the particulars of a compliance plan. The commission may, of course, want to insure that good planning is being conducted by its utilities; but a properly functioning incentives system should encourage good planning by the utility with little prompting from the commission.[20]

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 is likely to assist in the development of the market. Moreover, it could be argued that some type of incentive system is required for the development of an *efficient* market. This is because current regulatory practices will usually not provide sufficient incentive to use the market. Although a market-based mechanism will not guarantee that the expected saving will materialize, such a mechanism may make it more likely.

Regional and other national market-based environmental control programs, such as offset programs and allowance trading, are likely to be used more in the future. Market-based offset programs to limit nitrous oxide and other pollutants are already being used in California and a regional program (covering eight states) has been

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[20] Another reason is because often the market risk, either explicitly or implicitly, is shifted away from the utility and toward the ratepayers. It is difficult to justify shifting the risk and concurrently allowing the utility to profit from good decisions. The risk and reward or penalty should, therefore, be commensurate, as they are in a competitive market. For more discussion on this point see, Rose, *Public Utility Commission Implementation*, Executive Summary and Chapter 6.

proposed for northeastern states.[21] National and even global carbon dioxide trading have been discussed. Eventually, much or most of a utility's environmental compliance could be associated with market-based environmental programs. These programs would also function more efficiently within compatible economic regulatory procedures. Further study is required, however, on how these varied programs can be coordinated by a commission in an incentives approach.

There is little doubt that current regulatory mechanisms can be 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 they are an improvement over the way things are currently done. When choosing their regulatory procedures, commissions should consider the effect of their actions on the development of the allowance market and regard it as an important cost-saving factor. A change from traditional to more incentive- or market-based regulation is intended to improve the chance of success of the allowance market and minimize the compliance costs ratepayers will have to incur.

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[21] Northeast States for Coordinated Air Use Management, *Development of a Market-Based Emission Cap System for NO_x in the NESCAUM Region: Project Summary for Section 105 State Air Grant Funds for Market-Based Initiatives*, Submitted to U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1992.

UTILITY REGULATORS AND THE MARKET FOR EMISSION ALLOWANCES

by

Douglas R. Bohi[1]

It is probably safe to say that when it comes to emission trading under the Clean Air Act, a concern of most in the industry is the effect of this new form of environmental regulation on the industry and the way it is regulated. The author would like to express a different concern, and that is the effect of the industry and the way it is regulated on the emission trading program. The reason the author takes this view is that emission trading must prove to be successful in lowering the cost of reducing sulfur dioxide (SO_2) emissions if this approach to environmental regulation is to be regarded as a viable substitute for traditional command-and-control regulation.

The concept of emission trading has been recommended by economists for decades (at least since 1972) as a more efficient approach to regulate some kinds of pollutants. It is one of those concepts that may work well on paper but has not yet been proven in practice. Its application to the electric industry is such a test to see how well the market for trading emission allowances will actually work.

How is the market supposed to work? A couple of assumptions are needed to begin. One is that the costs of abating SO_2 emissions vary a great deal across different generating units (if costs were the same for all plants, the same result could be achieved by requiring each plant to cut back emissions by a fixed amount). A second assumption

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is that the owners of the plants must have the incentive to minimize their compliance costs; that is, that they will take advantage of the opportunity provided by emission trading to reduce their compliance costs. The idea is that utilities know better than the government the cheapest way to reduce emissions, and the emission trading program gives utilities the freedom to choose their preferred course of action. If each utility chooses the cheapest option, then the nation as-a-whole will have minimized the cost of reducing SO_2.

Whether utilities will actually have the incentive to minimize their compliance costs is an issue that will be returned to in a minute. First, it may be useful to see where the cost savings come from. To take a simple example, suppose it costs firm A $200 a ton to clean up their emissions and it costs firm B $300 a ton to clean up their emissions. It is possible for firm A to clean up more emissions than necessary to achieve compliance and to sell the excess allowances to firm B at a profit. As long as firm B pays firm A more than $200 a ton for their allowances, it is worthwhile for firm A to trade; and as long as firm B pays less than $300 a ton, it is to their benefit to buy allowances and cut back on abatement. The combined savings from trading allowances is $100 per allowance. The sum of all similar savings for all utilities that trade equals the nation's total savings from emissions trading.

The total possible cost savings from a properly functioning emissions trading market are estimated to be about $2 billion per year. In an industry with annual sales approaching $200 billion, $2 billion may seem insignificant. However, the potential loss to the nation is a lot larger than $2 billion in savings to the electric industry. The failure of the allowance program will almost certainly mean a setback for similar approaches to regulate other pollutants and environmental control costs in other areas will be larger than necessary on the industry.

As mentioned before, the success of emissions trading requires that firms in the industry have the incentive to minimize their compliance costs, and regulation can, of course, distort the incentives of utilities away from cost minimization. Unlike firms in competitive markets, regulated utilities do not necessarily make more profits when they reduce their costs. And, even when utilities try to minimize their costs, the costs they are trying to minimize may not be the same costs as those borne by society or by ratepayers. Regulation can make more expensive environmental compliance options look less expensive to the utility and less expensive options look more expensive. As a result, an environmental compliance plan may be perfectly consistent with the interests of the utility's shareholders and yet inconsistent with the interests of ratepayers and of society.

To say that utilities must have the incentive to choose the least expensive compliance plan simply means that utilities must have the incentive to buy allowances when they are the least expensive option and the incentive to sell allowances when some other option is less expensive. Moreover, these incentives should work this way even for utilities whose generating units are already in compliance. Generating units in compliance will receive enough allowances to cover their emission rates. If the program is to work correctly, the owners should not be complacent about this happy situation. They should seek to sell some of their allowances when the unit cost of abating emissions from the plant is less than the price of allowances. In this case the sale of allowances would more than cover the cost of taking the abatement action and the utility's ratepayers would benefit from the cost savings.

Whether or not utilities will buy and sell allowances as intended depends on the actions of the public utility regulators.

Setting the Cost Recovery Rules

Utilities are expected to compare the cost of fuel switching, scrubbing, repowering, environmental dispatching, demand-side management, and holding allowances, to determine which combination is the least-cost compliance strategy. For regulated firms, the cost of each of these alternatives is not determined simply by the acquisition cost of the item but also by the way the regulator allows the utility to recover its costs. There are many cost recovery rules set down by the regulator such as the allowed rate of return on capital, which will be used to illustrate how the incentive to buy or sell can be distorted.

Some compliance costs will be treated as current expenses to be recovered in the period in which they occur and some will be treated as capital expenses on which the utility earns a rate of return to be amortized over time. The magnitude of the allowed rate of return relative to the utility's cost of capital will be important in determining the relative cost of compliance options to the utility.

If the utility's allowed rate of return is less than its cost of capital, each additional capital expenditure will lower stockholder's equity and the utility will tend to prefer compliance options that are expensed over those that are treated as a capital cost. Because all of the costs are recoverable, this preference will hold, even when the options that can be expensed are more costly than those that are capitalized. In this circumstance, treating allowances as a current expense (as in the revision of the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA)) will lead utilities to prefer holding too many emission allowances and investing in too little abatement.

The problem that results from this bias in preferences is not a dirtier environment, since the total level of emissions is fixed in line with the total number of allowances that are available. Rather, the problem is that the wrong plants may be cleaned up. Some utilities will be abating emissions that should be holding allowances, and vice versa, so that total costs will not be minimized. In addition, the price of allowances will be too high because of the excessive demand for a fixed number of allowances. When new capacity is brought on line in the future, it will be equipped to eliminate more emissions than necessary, and at a higher cost than necessary. In effect, the excessive use of allowances by existing capacity will reduce the availability of allowances for future capacity.

There is also the possibility of a bias against the entry of truly independent power producers relative to utilities or utility affiliates. Independents must take their chance in the allowance market while utilities receive many or all of their allowances from the original government allocation.

The opposite effect will occur in states that are generous with the recovery of capital costs, so that utilities have a preference for capital investment options over those that are expensed. Treating the cost of allowances as a current expense will lead to a lower demand for allowances, and to a lower allowance price, than is appropriate. It is possible that there will be a greater reduction of emissions than required by law but this is unlikely. Instead, the price of allowances will decline until there is sufficient substitution of allowances for abatement to absorb the available supply of allowances. Also, new capacity will come on line with less stringent emission controls than desired because it is cheaper to hold allowances. In effect, there will be a transfer of emissions (and allowances) from existing generating units to future generating units.

The compliance decision is further complicated as a result of the rate of depreciation applied to capital investments. Except in circumstances where the rate of return on capital investment is so generous that investors do not wish to recover their equity, utilities will find a faster rate of depreciation more appealing than a slower rate. A faster rate, in effect, lowers the cost of capital investment. Allowances, in contrast, are not likely to be depreciated (as in the FERC accounting Rule) and acquisition costs will be recovered only as they are used up. The parallel between using up allowances and using up capital equipment need not cause a distortion in preferences between the two options unless the actual depreciation rate on capital differs from the true economic rate of using up the capital stock. For example, if the actual rate exceeds the economic rate of depreciation, a bias is created in favor of capital investment.

Another point should be mentioned in this connection; namely, the treatment of carrying costs for allowances that are held in inventory for future use. Unless those costs are fully recoverable, utilities will tend to shift their preferences away from holding allowances to meet compliance.

The Incentive to Sell and the Capital Gain

The prospect that a utility can lower its compliance costs by selling allowances and buying an abatement investment is probably not sufficient incentive by itself to encourage the utility to make the correct decision, simply because the utility encounters significant transaction costs and regulatory risk when it sells allowances. Confidence that the correct outcome will occur would increase if the utility were compensated for its trouble by keeping a share of the cost savings that would result from the sale of allowances. However, this practice would go against the regulatory tradition of crediting capital gains to ratepayers rather than to shareholders. This is where the distinction between sales of allowances and sales of any other assets must be recognized. Normally, a utility does not acquire an asset with the intention of selling it when a capital gain could be earned. Emission allowances, in contrast, are expected to be bought and sold when it is profitable to do so, or else the emissions trading program will not work as intended.

Unfortunately, it is not a simple matter to determine exactly when the utility should be allowed to earn a profit (and where things get a little complicated). Once the utility is allowed to profit from the sale of allowances, you open the door to rent-seeking behavior and there is the possibility that too many allowances will be sold, or sold at the wrong time. One reason this can happen is that the endowment of allowances given to the utility by the government enters the utility's books at zero value, and will earn a zero rate of return, while the combined sale of those allowances and purchase of abatement equipment can effectively convert those allowances into income earning assets with a positive value. Even allowances purchased on the market might be subsequently sold at an inappropriate time if the utility can freely substitute abatement investments for allowances.

The incentive to sell too many allowances can be eliminated if the utility is required to credit income earned from the sale of allowances toward the purchase of abatement investments or toward the purchase of additional allowances. In this way, the sale and immediate purchase of allowances would achieve a net gain to the utility, even though the original purchase value of the two sets of allowances may have increased. However, not all of the income should be credited to the purchase of abatement equipment all of the time, or else the utility's incentive to sell allowances would be reduced too much. In fact, all of the income earned from the sale of allowances should be credited toward the purchase of abatement options only in the case where the generating unit in question is exactly in compliance to begin with; that is, where the government allocation of allowances to that plant exactly equals emissions. In this case, any sale of allowances and corresponding purchase of abatement that earns a profit and achieves compliance is an economically correct decision. Compliance costs would go down as a result of the switch from allowances to abatement and the cost savings should be shared between the ratepayers and shareholders of the utility.

For a generating unit that is not already in compliance, and where the utility must invest in abatement, it is unlikely that the amount of revenue earned from the sale of allowances would cover the cost of abatement required to replace the allowances and bring the plant into compliance. This situation will occur even though the cost of abatement is less expensive per ton of SO_2 than the price of allowances; that is, even when it is economically correct to sell allowances and buy abatement. The absence of any net revenue from the allowance transaction means that there is no profit incentive to encourage the utility to take the correct action. As noted before, removing the profit incentive means that the utility is likely to follow a compliance plan that involves holding more allowances and using less abatement than it should.

To give the utility the proper incentive, the revenue earned from the sale of allowances should be used to cover only that part of the cost of abatement required to offset the SO_2 tonnage of allowances sold. Any additional revenue may be regarded as a cost savings to be shared between ratepayers and shareholders. The additional cost of abatement required to achieve compliance would be recovered in electricity rates.

This recommendation may not be popular with regulators and ratepayers because it means that the utility will be making a profit on the sale of allowances at the same time that ratepayers are asked to pay an additional amount for pollution control. Yet, this outcome is better for ratepayers than the one in which the utility sells no allowances and simply buys additional abatement, since at least part of the additional cost of abatement would be offset by the profit from the sale of allowances.

The recommended course of action is not likely to be popular with regulators either because of complications in determining how much of the cost of abatement should be paid out of the profits from the sale of allowances. Abatement investments such as scrubbing and repowering are both complex and lumpy and do not permit the calculation of a simple linear relationship between the cost of investment and the reduction of SO_2 that offsets the sale of allowances.

Conclusion

This brief discussion of the incentives necessary to encourage the correct actions on the part of utilities when buying and selling allowances touches on only a few of the issues. Nevertheless, it illustrates the difficulty involved in trying to make incentives compatible with efficiency in a regulated industry. In trying to provide for the proper incentives, the utility inevitably gains an opportunity to take advantage of the rules to earn excessive returns. In trying to close the loopholes, the rules become more complex and tend to dilute the incentives that were intended in the first place.

Accounting problems are minimized if the regulator simply ignores the incentives required for an efficient allowance trading market. This, in fact, is what the FERC proscribed for the treatment of allowances in its USOA. Since state public utility regulators do not have the responsibility of managing environmental regulations, it is all too likely that they will willingly follow FERC's lead. (Consequently, the argument has come full circle: it is too bad that the experiment with emissions trading is being tested in a regulated industry.)

This may seem a harsh conclusion, particularly with the multiple and often competing objectives expected of public utility regulators. In addition to regulating utilities, they are often charged to undertake employment and economic development objectives, to operate social welfare programs that involve charging some customers more in order to charge other customers less, to undertake environmental programs at customer expense that may or may not yield a direct environmental benefit (such as tree planting in a rain forest). When these objectives conflict, the regulator cannot be criticized for failure to accomplish them all. Nor does it matter from a national perspective, since the costs of such choices are usually borne locally with little or no spillover on other states that have no voice in the decision.

Such is not the case with the emission trading program, because each state's policy choice can affect the other states. For example, a state that mandates scrubbing even when it is relatively costly, to benefit the local coal industry or to attain a cleaner air standard, will serve to increase the net supply of allowances on the market and depress their price. This will reduce the cost of allowances to other states and reduce the likely amount of abatement they undertake. The cost of the Acid Rain Program will decline, and the environmental cost of adding new capacity will not be as high, compared to an optimal program. This may not sound so bad because the burden is being borne by the state that chooses a more costly approach. Nevertheless, the wrong plants will be cleaned up and the total cost of the program will be too high.

Conversely, and probably more serious, a state that encourages excessive holding of allowances (because of relatively unfavorable cost recovery treatment of other compliance options), will drive up the price of allowances and force other states to undertake more abatement than they should. All states will be paying more for the Acid Rain Program than they should, the wrong plants will be cleaned up and environmental costs imposed on future capacity will be too high. As in the other case, fewer benefits will accrue to the nation from using emission trading and the concept may end up with a tainted reputation.

Regardless of the spillover effects, it is still in the interest of the other states to pursue a minimum cost strategy.

DISCUSSION PAPER ON WHOLESALE RATEMAKING CONSIDERATIONS FOR SULFUR DIOXIDE EMISSIONS ALLOWANCE TRADING

by

Eliot Wessler[1]

Introduction

The acid rain provisions of the Clean Air Act Amendments of 1990 (CAAA) created an allowance trading program for sulfur dioxide (SO_2) emissions from electric utility power plants. Theoretically, the trading program will provide utilities the flexibility to control their SO_2 emissions at minimum aggregate societal costs. The trading program represents a significant change from command-and-control environmental policies of the past. It is the first large-scale experiment in the United States in using market mechanisms to control harmful power plant emissions.

A continuing concern is whether the market-oriented trading program is compatible with the pervasive rate regulation of the electric utility industry. Economists accept, as an article of faith, that traditional rate regulation policies tend to provide incentives for utilities to minimize risks, rather than costs. To the extent that this is true, the allowance trading experiment is not likely to be successful.

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A number of commenters have described proposals for alternative regulatory policies to provide utilities with appropriate incentives for cost-minimization.[2] These proposals focus on utility incentives at a "macro" level, including potential "A-J" biases and potential biases that result from the prudence doctrine.

This paper has a "micro" level focus. It examines options for ratemaking that may also influence utility incentives for cost-minimization. The intent is to provide a structured discussion of the different types of transactions that involve allowances, with emphasis on the implications of allowance trading on ratemaking for wholesale power sales. Although the discussion does not explicitly consider retail power sales, some of the same considerations that apply to wholesale ratemaking may also apply to retail ratemaking.

Four generic types of allowance transactions are examined:

- Type 1: Unbundled Allowance Sales,
- Type 2: Wholesale Power Sales,
- Type 3: Pooling Arrangements,
- Type 4: Holding Company Transactions.

Each of these four generic allowance transactions is assessed along two dimensions: jurisdictional issues and wholesale ratemaking considerations.[3]

Type 1 Transaction: Unbundled Allowance Sales

Some transactions will involve a sale of allowances but no associated sale of power. The form of payment for the allowances may be cash, an exchange involving

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[2] See, Kenneth W. Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992).

[3] The effort here is to identify issues, not necessarily to resolve them. Many of the issues raised will require significantly more thought than is reflected in this discussion paper. Some ratemaking options are discussed conceptually. No recommendations on ratemaking options are made, and no endorsement of any option should be inferred.

allowances, or other compensation. Contract terms of the transaction may be relatively simple or complex. A simple example is a cash deal for a relatively small number of allowances to be used by the buyer in the current year. A complex example is a sale of a stream of allowances or a transaction involving noncash compensation.

At some point, all utilities may be both sellers and buyers in the allowance trading market. However, generally, utilities will probably be net sellers if they have relatively low marginal control costs; utilities will probably be net buyers if they have relatively high marginal control costs. Note too, that industrials may "opt in" to the allowance market and brokers may also participate.

Jurisdictional Issues

Both the FERC and the state commissions have jurisdictional authority to establish "just and reasonable" rates. To the extent that utilities either buy or sell unbundled allowances either to achieve compliance or otherwise benefit ratepayers, the revenues and costs of those transactions will be reflected in power rates. Thus, regulators clearly will regulate the "back end" of the transaction, that is, when utilities include the costs and revenues of allowance transactions in power rates.

The controversy involves whether regulators will exert jurisdiction at the "front end" of the transaction. Moreover, regardless of whether a commission has direct jurisdiction over an allowance transfer,[4] regulators may indirectly exert jurisdiction over an allowance transaction in advance by requiring a utility to forego a transaction, or perhaps by permitting a transaction only if the utility agrees to a change in price or terms and conditions of the sale.

There is considerable concern that front-end regulation of allowance transactions may hinder the development of an efficient allowance trading market. Therefore, some

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[4] In its Notice of Proposed Rulemaking on the Clean Air Act Amendments' accounting issues, the FERC stated that it did *not* believe that the transfer of allowances was subject to Federal Power Act (FPA) Section 203, 56 *Federal Register* 65467 (December 11, 1991), FERC Docket No. RM 92-1.

commenters have argued, on policy grounds, that it may be harmful if FERC--or state commissions--engage in significant front-end regulation of allowance transactions. However, of equal concern is the need for clear "rules of the game" so that utilities understand the likely ratemaking consequences of various compliance strategies before implementing those strategies.

Wholesale Ratemaking Considerations

The two major ratemaking issues are the *timing* of recognizing costs and revenues of allowance transactions in wholesale rates and the *price* of allowances.

Timing Issues

The revenues and costs of unbundled allowance transactions may be recognized in rates on a current basis or on a deferred basis. For example, when a utility *buys* allowances to come into compliance:

- Current recognition means that allowance purchase costs are recovered in rates on a current, test-year basis. This would put the ratemaking treatment of allowances on a par with the recovery of operating expenses. One specific alternative is that the costs of allowance purchases may be flowed through the fuel adjustment clause. This would minimize the risk of recovery of the allowance purchase costs.
- Deferred recognition means that allowance purchase costs are added to the rate base and are reflected in rates as an amortization expense, with the unamortized balance earning a return. This ratemaking treatment, which puts the allowance purchase on a par with the treatment of a capital investment, might be used for allowances received under a long-term contract. Utility capital investment may qualify for construction-work-in-progress (CWIP) treatment. FERC's policy is to allow 100 percent of CWIP for pollution control equipment

such as scrubbers. It is believed that a majority of states have similar CWIP policies for pollution control equipment.

Similar timing options are possible when a utility *sells* allowances. That is, the revenues from an allowance sale could be used as a current offset to rates or could be deferred and used as an offset to rate base. The deferred revenue would be amortized as a reduction to a utility's rates in future years. Choosing the appropriate ratemaking treatment may be a function of the circumstances of the transaction or as a function of rate effects including the effect on rates for different customer classes.[5]

One extremely important consideration would be for regulators to adopt ratemaking treatments that will provide efficient incentives for utilities to pursue a least-cost compliance strategy. Ideally, the regulatory treatment of allowance transactions should be neutral with respect to the incentives to engage in allowance trading. The regulatory treatment should not bias the utility's decision with respect to the compliance strategy tradeoffs between relying on allowance trading and other compliance options.[6]

Some observers fear that, at least without clear rules of the game, allowance trading will increase regulatory risk for utilities without some corresponding compensation. Those observers would argue that some incentives to engage in efficient trading may be warranted.

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[5] As an example, including the allowance transaction in the rate base would tend to increase the demand component of rates. This would tend to have the greatest impact on low load factor customers such as residential customers. Current recognition of the allowance transaction would tend to increase the variable component of rates. This would tend to have the greatest impact on higher load factor industrial and commercial customers. These customer class considerations are probably less problematic for FERC than for state commissions.

[6] If a compliance investment such as a scrubber is capitalized, but allowance purchases are expensed, the utility may have an incentive to scrub instead of trade, even if trading is a lower cost compliance option, since it will earn a return on the capitalized scrubber costs but will earn no return on expensed allowance purchase costs. In addition, regulatory policies on how fuel is expensed may produce biases with respect to a utility's choice of fuel switching as a compliance option.

Price of Allowances

It is hoped that the allowance trading market will be reasonably competitive. To the extent this is true, the price of allowances will be driven by market forces.[7]

In most cases, regulators will likely require that utilities' rates reflect the actual costs or revenues from allowance transactions. However, in at least two special cases, FERC may wish to consider an alternative ratemaking treatment:

- Affiliate deals[8] involve, for example, a utility selling unbundled allowances to its affiliated power producer. The utility might have an incentive to sell allowances to its affiliate at the lowest price possible. If the sale price is less than market value, there is an apparent equity and efficiency problem. The affiliate would appear to be receiving a subsidy from the utility. The affiliate may, for these reasons, enjoy a competitive advantage in the generation market.[9]

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[7] There are a number of reasons why allowance prices may not be market-driven. One reason is that utilities may not minimize compliance costs, particularly if there are inefficient incentives for compliance planning. A related reason is that buyers and sellers may not make economically rational decisions about market participation if there is significant regulatory intervention. Prices will also be distorted if a seller or some group of sellers dominates the allowance market. The regulatory problems that may result from such market power are beyond the scope of this discussion paper.

[8] Other types of allowance transactions, including bundled (power and allowance) transactions and holding company transactions, would present similar problems. The special problems of allowance sales by operating companies within a registered holding company are discussed below.

[9] If the affiliated power producer is able to acquire allowances at less than market price, when its competitors must pay market price to acquire allowances, the affiliate would enjoy a competitive advantage that results from the affiliate relationship, not from greater efficiency. This raises the issue of whether generators that must buy their allowances, presumably at market price, can compete successfully in generation markets with utilities that can use allowances from inventory, including "free" allowances from the EPA. One solution would be to require utilities carrying an inventory of allowances to provide a revenue credit to their native-load customers equal to the market value of all allowances connected with off-system sales. To the extent this occurs, utility offers to sell should reflect the market value of allowances in the offered price.

- Imprudence may be found if the price of an allowance transaction differs significantly from the "market" price. For example, an allowance buyer might be found to have paid too much for allowances, in which case a lower price for allowances could be imputed in rates. Alternatively, an allowance seller might be found to have sold too low, in which case a higher price could be imputed in rates.

In addressing both of these special cases, regulators may find identification of a "market" price difficult, particularly if contractual arrangements throughout the industry are complicated. There is unlikely to be a single "market" price that regulators will be able to identify as the appropriate price to be imputed to rates. This problem may be reduced if there is an active futures market in allowances, which would tend to make prices converge to a single market price.

Type 2 Transaction: Wholesale Power Sales

These will most likely be bundled transactions involving wholesale power and allowances.[10] There are two types of wholesale power sales:

- Requirements Sales. These are for firm power, usually under long-term contracts. The seller generally considers requirements sales to be part of its native load, in that it plans its system specifically to provide for the current and future needs of its requirements customers during the contract term. Requirements customers are at risk to pay for the prudently incurred investments

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[10] Note that two types of arrangements are possible: the power seller can use its own allowances to cover emissions associated with the power sale or the power buyer can furnish the needed allowances to the power seller. Although there may be many transactions in which the power buyer does furnish allowances to the seller, the more immediate ratemaking problems appear to be associated with the power seller providing the allowances. When the power buyer furnishes allowances, this rate will eventually reflect some measure of the value of the allowances. When the power seller uses its own allowances, FERC will be required to determine the value of the allowances in the wholesale power rate.

and expenses of the seller. For these reasons, requirements sales are similar to retail sales.

- Coordination Sales. In contrast to requirements sales, coordination sales may be firm or nonfirm, may be short term or long term. In any case, these sales are made at the discretion of the seller. The seller is not under obligation (except as provided by contract) to plan its system to provide coordination service. Coordination customers generally are not at risk to pay the total fixed costs of the seller in the same way that requirements customers are at risk to pay these costs. To the extent that coordination rates do collect fixed costs, these fixed costs are generally revenue credited to the native-load customers, thereby lowering requirements and retail service rates.

Jurisdictional Issues

With the exception of special issues associated with registered holding companies, bundled power and allowance transactions do not seem to present any new jurisdictional issues. These transactions appear to be FERC-jurisdictional because they involve wholesale power sales and because the allowances are an input used by the seller in the production of the power, just as fuel and plant are inputs. Although FERC would have sole jurisdiction over the rates for this type of transaction, in most situations state commissions would retain authority to challenge the prudence of a wholesale purchase decision of a state-jurisdictional utility under the Pike County doctrine.

Wholesale Ratemaking Considerations

The following discussion assumes a traditional ratemaking approach to risk and reward.[11] Wholesale requirements customers generally are at risk for the wholesale

[11] A number of current proposals would change the traditional allocation of risks and rewards, particularly with respect to regulatory risk. These proposals range all the way from prudence preapproval to placing all compliance investments "below the line." Observers generally agree there should be symmetry between risks and rewards.

allocable portion of compliance costs. That is, requirements rates include all prudently incurred compliance costs and the benefits that flow from compliance planning, such as trade gains from allowance trading, would go to ratepayers.

Requirements Rates

Requirements rates are based on cost-of-service principles similar to those used by most states in setting retail rates. Under the traditional approach to requirements ratemaking, requirements customers would be at risk for the costs of compliance options such as scrubbers and fuel switching, as well as the costs and revenues associated with allowance trading. By extension, this traditional approach would dictate that if requirements customers are at risk to pay for prudent compliance costs, they would get the benefits (losses) of any trade gains from allowance sales.

Under this traditional approach, the requirements (and native-load retail) customers would get the benefits of the "free" EPA allowances by having their rates reflect these allowances at their zero historical cost. If allowances are purchased to meet these customers' loads, their rates would reflect only those allowances allocable to their service. To the extent that the utility makes off-system sales, those sales would have to be supported by remaining allowances in inventory or by the purchase of allowances. The general principle applied here is that the utility would dedicate the lowest cost allowances in inventory to the requirements (and native-load retail) customers as a *quid pro quo* for these customers, assuming risks for compliance costs.[12]

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[12] Note that this type of ratemaking approach would require that regulators have available data on the specific identification of the source of allowances and the associated costs. These data should be available from the utilities' accounting records.

Coordination Rates

There appears to be general agreement that coordination rates should reflect the value of allowances in the allowance trading market. One policy concern is that if they are given for "free" to coordination customers, the requirements customers of the selling utility would be bearing the opportunity costs of the allowances. One argument is that this would amount to a subsidy for off-system sales by native-load customers.

Coordination rates can be either market-based or cost-based.

Market-Based Rates

In order for FERC to approve a market-based coordination rate, the seller must demonstrate that (1) neither the seller, nor its affiliates, have market power in generation or transmission, or if they do have market power, that it has been adequately mitigated, and (2) that the seller has not engaged in affiliate abuse activity.[13] The seller is not required, however, to present evidence regarding its costs.

Continuing this practice regarding cost evidence would mean that FERC would not require data on the seller's cost of allowances, just as FERC does not now require data on the seller's cost of generation. Such flexibility would mean that sellers may be able to charge coordination prices that reflect a component of price up to the market value of allowances. The allowance component of the price would likely be capped at the market value of allowances because alternative power sellers have the potential to bundle power and allowances at the market value of those inputs. This would likely restrain power prices to market value or near market value.

However, if the seller has market power in the allowance trading market, or if the allowance trading market is otherwise not workably competitive, then the rationale for

[13] For a general discussion of FERC's standards for market-based pricing, see, Bernard W. Tenenbaum and J. Stephen Henderson, "Market-Based Pricing of Wholesale Electric Services," *The Electricity Journal* (December 1991).

allowing sellers flexibility on power pricing may be questioned. This is because allowances are an important input to electricity production, and market power over this input might extend to the bulk power market. One option would be for FERC to assess market power and affiliate abuse in relation to the power seller's use of allowances to support the market-based power sale.

Cost-Based Rates

This is still the dominant pricing regime for coordination service. FERC generally gives coordination sellers flexibility to use one of two alternative cost-based pricing approaches. The first approach has split-savings rates, in which the price is capped at no more than the seller's incremental cost, plus a margin that is no more than the midpoint of the incremental costs of the seller and the decremental costs of the buyer. The second is an embedded-cost price cap, which is the sum of the incremental fuel and operating costs plus a demand component up to the fully allocated embedded demand cost of the seller.

Either pricing method may include some, though not necessarily all, of the compliance costs. For example, the incremental fuel and operating costs of the seller may reflect some of the changes in its operating expenses caused by compliance options taken (for example, higher fuel costs from fuel switching). The demand component of the coordination rate may reflect compliance investments made by the seller, such as scrubbers, which would be consistent with a traditional ratemaking approach to capital investment. The fact that the rate includes some, though not necessarily all, of the seller's compliance costs is consistent with FERC's policies on coordination rates.

However, in some circumstances, additional adjustments may be necessary for cost-based coordination rates to reflect the value of allowances used to support such sales. For the reasons discussed above, some have suggested an "adder" to account for the cost and quantity of allowances needed to cover the incremental emissions occasioned by the sale. Adders would need to be designed so that sellers can only charge buyers for allowances that were used to support the sale. Otherwise, the adder would violate the principles of a cost-based rate.[14]

FERC could use a number of conceptual pricing options for the allowance adder:

- Weighted-average historical cost is the proposed accounting value, which includes the historic costs of EPA-allocated allowances and purchased allowances.
- Incremental cost would reflect the cost to the utility of the allowances used to support the sale. This option requires specific identification of the source of allowances. If allowances are purchased to support the sale, the incremental cost would be the purchase price. If allowances come from the utility's inventory, in part or in whole, the incremental cost is more difficult to define. It could be some measure of the incremental cost of the utility's compliance plan (for example, the marginal cost of the last ton of emissions controlled).
- Market value would reflect the "market" price of allowances. As discussed previously, there is not likely to be a single market price, at least initially. Thus, this pricing option may produce the most disagreement on how it is to be measured.

Various efficiency and equity considerations are involved in choosing a pricing option for a cost-based coordination rate adder for allowances. With respect to efficiency, the closer coordination prices move to market value, the more efficient they will be, all other things equal. A market-based adder for allowances would move the coordination price closer to market value with respect to one component of the rate, though not necessarily with respect to the total price. For example, a cost-based coordination rate that is higher than market value will be moved further from market

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[14] For example, if the incremental generation used to make the coordination sale comes from baseload coal-fired generation, then there will be incremental emissions which must be covered by allowances. However, if the incremental generation comes from natural-gas-fired capacity, then there are no incremental emissions. This generally tracks FERC's policy regarding the calculation of incremental fuel and operating costs that may be included in coordination rates. Historically, sellers have identified the generating unit that is being used to make the sale and the fuel costs associated with that unit.

value if a market-based adder for allowances is used.[15] Thus, it is not clear what efficiency effect using a market-value adder would have.

The equity considerations are even more difficult. If the weighted average inventory cost of allowances is less than the market value of allowances, using this type of adder could mean that native-load customers will be subsidizing coordination customers. Incremental cost or market value, either of which is almost certain to be higher than accounting value, would provide a larger revenue credit.

On efficiency grounds, using market value for ratemaking purposes would appear to have at least one significant advantage over the other options; that is, it may produce the least bias in the tradeoff utilities will face between selling allowances bundled with power or selling unbundled allowances. If a utility can sell unbundled allowances at a market price but must sell bundled allowances at a cost-based charge, it may have a disincentive to bundle allowances with power efficiently. If this disincentive is strong, this could have a significant adverse effect on bulk power trading.

Special Case of Unit Power Sales (UPS)

Several types of coordination sales may present special ratemaking issues. One special case is UPS. These sales are made from dedicated power plants, although most other coordination sales are made from the seller's system resources. Generally, UPS rates reflect the costs of the dedicated plant only, including capital and operating costs.

The problem presented by UPS is a cost allocation problem and will be most acute for UPS arrangements entered into prior to the passage of the CAAA. Utilities are expected to do their compliance planning on a systemwide basis; that is, consider all their generators in order to minimize overall compliance costs. This means that the

[15] A cost-based coordination rate may be higher than market value for the service if there is market power (for example, as a result of the buyer's inability to obtain transmission access to reach alternative sellers). In such cases, the coordination rate will be capped at the seller's embedded costs of service but this may be higher than what is otherwise the market price for the service.

specific compliance action at the UPS unit that will minimize systemwide costs may be significantly more or less costly than actions taken at other units.

The question, then, is what compliance costs should be allocated to the UPS rate. A number of options are available, including imputing an average compliance cost or imputing the cost associated with bringing the UPS unit into compliance. There are a number of considerations for pricing UPS, including the existing UPS contract, fairness to the UPS customer and other wholesale customers, and preserving incentives for the utility to pursue a least-cost compliance strategy. Many of the problems, however, may be avoided in future UPS arrangements as a result of the parties specifying these treatments in the contract.

Type 3 Transaction: Pooling Arrangements

A number of pooling arrangements may involve allowances. Some pooling arrangements, such as allowance bonus pools, may not appear to be FERC-jurisdictional and do not appear to present special wholesale ratemaking or accounting issues.[16] Two types of pooling arrangements with FERC-jurisdictional issues are:

- Power pools are categorized as either loose or tight. Loose power pools are arrangements based primarily on reliability considerations; they do not appear to present issues that are not also raised by coordination sales.[17] Tight power pools are usually centrally dispatched based on the incremental costs of each plant.[18]

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[16] Allowance bonus pools have been suggested as a hedge against risks associated with EPA rules to award bonus allowances based on a telephone queuing system.

[17] This is because in loose power pools, the members buy and sell power in much the same way that utilities outside power pools do. The only difference is that pool transactions are generally covered by poolwide rates, rather than an individual utility's tariff or rate.

[18] Note that registered holding companies, which are discussed in the next section, are a special type of centrally-dispatched system. Here we consider power pools that are not registered holding companies.

Overlaying an allowance trading market should not conceptually change this dispatch routine. What will change is that some measure of allowance value, such as market value, necessary to cover the emissions from each plant will need to be internalized into the dispatch routine.[19]

- Allowance reserve pools are arrangements that utilities are free to enter into in order to diversify risk of incurring an allowance shortfall. The contractual arrangements are up to the pool participants. The pools may run the gamut from bilateral agreements between two utilities to share allowance reserves, to a reserve pool that may encompass a large geographic region and many utilities (for example, a North American Electric Reliability Council region). Note that these are two very different types of transactions that present different types of jurisdictional, wholesale ratemaking, and accounting issues. The only obvious connection between the two types of arrangements is the fact that members of a power pool may elect to form an allowance reserve pool.

Jurisdictional Issues

Power Pools

Section 205 of the FPA requires interconnection agreements that specify the rates for power transfers between public utilities and others to be filed with FERC. Since these agreements were developed prior to the passage of the CAAA, they do not explicitly deal with how the value of allowances would be factored into central dispatch agreements. It is expected that amendments to power pool agreements will be filed that specify how pool service prices will change as a result of allowances.

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[19] For a proof of this proposition, see "The Effects of the 1990 Clean Air Act on System Dispatch and Marginal Costs," NERA Working Paper #12, October 1991.

Allowance Reserve Pools

Under section 205(c) of the FPA these pools may need to file their agreements with FERC as contracts affecting rates. However, it does not appear that FERC would need to approve such arrangements under FPA section 205 unless a utility seeks to recover the costs incurred as a result of participation in an allowance reserve pool as part of a FERC-jurisdictional power sale.

Wholesale Ratemaking Considerations

Power Pools

It is expected that power pools will amend their operating agreements and file the amended agreements at FERC. Since each power pool operating agreement is different, it is difficult to generalize about how the dispatch routine will change in centrally-dispatched power pools and how the costs of allowances will be allocated within the pool. However, pools are apt to allocate costs based on the actual dispatch that reflects allowance values.

Allowance Reserve Pools

With respect to allowance reserve pools, there do not appear to be special ratemaking issues. When a pool transaction takes place, such as a transfer of unbundled allowances between pool members, ratemaking considerations for unbundled allowances should apply.

Type 4 Transaction: Holding Companies

There are nine registered electric holding companies. Together, they will control about 25 percent of the initial allocation of allowances. Therefore, the actions taken by these companies are likely to have a major effect on the success of the allowance trading market.

The allowance transactions undertaken by registered holding companies will not differ operationally from the same transactions undertaken by utilities that are not part of a holding company. However, holding companies present some special jurisdictional, wholesale ratemaking and accounting issues compared with a nonholding company case, as discussed below.

Jurisdictional Issues

For ratemaking purposes, the public utility subsidiaries of registered holding companies are subject to the jurisdiction of both state and federal regulators. Jurisdictional issues involving registered holding companies depend in the first instance on the nature of the agreements among the affiliates, including the scope of joint planning and operation. Also, the agreements can be amended to apply to issues, such as allowance trading, that the current agreements may not address.

The jurisdictional scope of state ratemaking authority versus FERC ratemaking authority was addressed by the Supreme Court most recently in the Mississippi Power & Light Co. (MPL) case.[20] That case involved Middle South Utilities and the Grand Gulf nuclear facility.

The Mississippi Public Service Commission (MPSC) granted MPL an increase in its retail rates to allow it to recover the cost of purchasing an allocation of Grand Gulf power mandated by FERC. On appeal, the Mississippi Supreme Court ruled that MPSC erred by not first determining that the expenses were prudently incurred and also ruled that such a prudence inquiry would not violate the Supremacy Clause.

The U.S. Supreme Court, however, held that the Supremacy Clause required the MPSC to allow recovery of costs incurred in paying a FERC-determined wholesale rate for a FERC-mandated allocation of power. Otherwise, the Court said, the federally

[20] Mississippi Power & Light Co. v Mississippi, 487 U.S. 354 (1988).

mandated costs would be improperly "trapped." The Court explained that, in some circumstances, a state might examine whether a utility had voluntarily bought too much high-cost power when less costly power was available. This inquiry will be foreclosed once FERC has determined the just and reasonable allocation of power.

There is uncertainty about how these principles will apply to allowance trading. The CAAA, however, did not change the boundaries of state and federal ratemaking jurisdiction. That is, the Act expressly made no change of any kind in state law regulating electric utility rates, in the FPA, or in FERC's authority under the FPA.[21] Thus, a possible application of the above-stated principles to allowance trading would suggest that, once FERC determines the justness and reasonableness of wholesale rates, including the allocation of compliance costs, the states may be required to allow recovery of those costs in retail rates.

Different rules, however, may apply to exempt holding companies and to multistate utilities that are not holding companies.

Wholesale Ratemaking Considerations

Each registered holding company has a system-specific arrangement for cost equalization among its public utility subsidiaries as prescribed in the system's joint operating agreement. One model for achieving cost-equalization of systemwide compliance costs would be for operating companies to buy and sell allowances with each other.[22] A simple example illustrates this.

Least-cost planning for a holding company may dictate that a single operating company should overcomply because its marginal control costs are lower than those of

[21] FPA 42 U.S.C. § 7651b(f).

[22] Another model of cost allocation within holding companies might be a situation where the investment costs of compliance are allocated to the ratebase of each of the operating companies. This type of cost allocation model has not been considered in the following analysis.

the other operating companies. The operating company that overcontrols with respect to its own compliance needs would sell allowances to the other operating companies in order to bring those other operating companies into compliance.

Depending on the holding company operating agreement, this sale of allowances may be bundled with power or it may be unbundled. If the sale is a bundled sale, the value of the allowances would probably be reflected in the price of the energy that one operating company sells to another. Whichever the type of transaction, the ratemaking issue is the value of the allowances in the transfer price.

As in the case of ratemaking considerations for cost-based coordination sales, discussed above, there are a number of options for pricing allowance sales within holding companies. However, the major difference here is that the operating companies are affiliates, and so greater care may be required in monitoring the transactions. In addition, the allowance pricing mechanism used to achieve cost allocation may have a significant effect on the equity of the cost allocation between operating companies.

There are a number of ratemaking options for pricing allowance transfers between operating companies,[23] including:

- Weighted average historical cost is the proposed accounting value of allowances in inventory, including EPA-allocated allowances as well as purchased allowances.
- Incremental cost would be the costs associated with that portion of the compliance plans necessary to free-up the allowances used for the interaffiliate sale. Stated another way, it would be the difference between the utility's portion of total systemwide compliance costs and the stand-alone compliance costs that the selling utility would incur. It is thus a measure of the costs of overcompliance which result in systemwide compliance cost savings.
- Market value is some measure of the market value of allowances.

[23] Note that these are effectively the same options for pricing allowances in coordination rates, as discussed above.

All these pricing options present equity problems. For example, if allowance sales are priced at the weighted-average historical cost, the operating company that overcontrols and sells allowances is unlikely to recover from the other operating companies the incremental costs of compliance undertaken to effect the systemwide benefits. The selling operating company would heavily subsidize the buying operating companies.

If incremental cost is used, the selling operating company is made whole with respect to its out-of-pocket costs. However, it receives none of the benefits of the reduced compliance costs for the system in total. In addition, to the extent that the selling operating company has taken on extra risk by taking the necessary compliance actions on behalf of the system, it would not be entirely compensated for that risk if incremental cost is the basis for pricing.

If market value is used, the selling operating company may or may not be compensated for the incremental costs (and risks) it has undertaken. This is because market value may be higher or lower than the seller's incremental cost. Thus, the selling operating company is taking all market risk under this option of changes in allowance prices. In addition, the "market" price agreed to by affiliates may not be a good reflection of actual market value.

Some principles worth considering for cost allocation between affiliates are:

- No ratepayers in any jurisdiction should ultimately pay more than the stand-alone costs that would be incurred by their own operating company.
- An operating company that overcontrols and sells allowances should be compensated for any additional risks it assumes by making the extra investments necessary to overcontrol.
- The benefits of systemwide compliance planning should be shared equitably. The distribution of the benefits should probably take into consideration any incremental risks assumed by an operating company.

Session IV

State-Federal and Multistate Issues

ALLOWANCE TRADING UNDER THE CLEAN AIR ACT: WHO SHOULD REGULATE, AND WHEN?

by

Reinier Lock[1]

Introduction

The goal of this paper is to explore how compliance with the Clean Air Act Amendments of 1990 (CAAA), especially Title IV and emission trading under it, will affect the current relationship between state and federal regulation. It is difficult, with the limited experience we have had under Title IV, to be definitive about or to be a very strong advocate of too many policy positions. What may be most helpful at this point is to identify where the difficult issues in state/federal relations might arise; and then to explore ways in which tensions might be either avoided or resolved.

One anticipated conclusion is that a traditional regulatory mindset could be very destructive if applied to this new area of oversight without due sensitivity to what Congress is trying to achieve in Title IV. That concern pervaded the early legislative debates; and it persists today. Title IV presents some unique challenges to state regulators and will require some creative solutions and fresh thinking if the goals of Congress are to be realized and the full benefits that allowance trading can offer are to be reaped by electricity consumers. In the ultimate analysis, Title IV amounts to a massive internalization of the external costs imposed on society by acid rain deposition. (This places in serious question the notion of

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additional externality "adders" for sulfur dioxide (SO_2) and nitrous oxide (NO_x) at the state level for utility supply planning purposes.)

The whole point of Title IV is to give those directly charged with compliance, namely power producers, the maximum flexibility to pursue least-cost compliance solutions. Perhaps the biggest single factor in how well they do this will be how state regulators respond to their compliance and allowance trading initiatives.

The Jurisdictional Backdrop

In the 1980s some major tensions developed in the traditional regulatory dichotomy between state and federal jurisdiction created under the Federal Power Act (FPA), centering on issues such as those arising from the Grand Gulf case. These tensions produced a series of Federal Energy Regulatory Commission (FERC) and court decisions that ultimately led to the Mississippi decision. Although that case decided who did and did not have jurisdiction in the circumstance of cost allocation within a multistate holding company, it did little to resolve the underlying tensions.

Also in the 1980s, the rapid evolution of the Public Utility Regulatory Policies Act of 1978 (PURPA) model was seen. Power produced under PURPA far outgrew the original expectations of Congress and soon became one of the major avenues for new power supply in the bulk power markets and contributed significantly towards the growing competitiveness of those markets. Leaving aside the holding company area or whatever is the perceived scope of the Mississippi decision, both FERC and state regulation have responded in reconciling the traditional FPA and the PURPA regulatory regimes and in dealing with the new conditions of the bulk power markets.

This reconciliation has primarily involved state commissions channeling PURPA and other power supply options into competitive bidding or procurement schemes, and placing those schemes within the broader context of "least-cost" or "integrated resource" planning (IRP), which, of course, can include demand-side measures and even environmental externalities. FERC, on the other hand, has encouraged the competitiveness of those bulk power markets and attempted to relieve barriers to their competitiveness (such as the lack of transmission access); and FERC has encouraged and attempted to pay due deference to the results of state competitive procurement schemes. Although this has not always worked perfectly, as the TECO and Nevada Sun Peak cases illustrate, it is generally a workable model. It relies upon the Narragansett/Pike County dichotomy to reconcile preemptive FERC jurisdiction over the justness and reasonableness of wholesale power sales (the Narragansett doctrine) with the ability of states to assess the prudence of utility Purchases (the Pike County doctrine).

In a sense, the Mississippi decision is an exception to this rule of jurisdictional comity, an exception driven by the fact that a prudence review of the actions of an operating subsidiary is not a viable concept in the context of a centrally-managed holding company. However, stating the rationale for Mississippi does not resolve the underlying policy questions that trouble state commissions. Unfortunately, the present legislative debate indicates little true understanding or desire to address these issues.

Title IV and Economic Regulation

There is another set of institutional and jurisdictional relationships that are equally critical in defining the role of state commissions in this area which are relatively undeveloped. Early in the legislative debates on the CAAA there was discussion of "the big institutional issue:" how Title IV and other interactive parts of the CAAA, enforced by EPA and by state environmental agencies, would interact with "economic" regulation (that is, FERC and Securities and Exchange Commission regulation at the federal level and state public utility regulation). This appeared to be one of the toughest issues Congress would have to address and, of course, Congress never really did address it. Congress simply ran out of time.

What Congress did in Title IV is what Congress typically does when it does not know how to deal with certain areas of governance, it "saves" them. Hence, we have in section 403(f) a series of savings provisions effectively stating that Title IV does not require changes of any kind in state public utility regulation or in FERC jurisdiction under the FPA or in state competitive bidding programs, which, of course, are built upon both federal and state authority. The only explicit effort in Title IV to limit in any way the application of economic regulation is a provision that the Public Utility Holding Company Act of 1935 (PUHCA) is not to apply to the acquisition or disposition of allowances.

While everyone now takes these preservations of jurisdiction for granted, it should be recognized that Congress, in fact, made a major policy decision in not attempting to prescribe how economic regulators should treat CAAA compliance, especially allowance trading. The fact that it made this decision largely by neglect does not lessen its importance. What it has left for state commissions is both a tremendous range of discretion and, accompanying that, a great deal of uncertainty as well as an enormous responsibility for handling properly what is viewed as one of the great experiments in environmental regulation for decades, that is, the use of an allowance trading rather than a "command and control" model of environmental regulation.

If state regulation fails to properly deal with this model, there are two possible results: either the demise of the Title IV experiment, or Congress revisiting its basic "hands-off state regulation" policy and prescribing to state commissions how they should treat Title IV compliance and allowance trading. Moreover, each of these outcomes is predicated upon the assumption that state commissions will inevitably mismanage the Title IV scheme. The challenge facing state commissions is very serious and quite imminent.

There have been a number of policy formulation dialogues that have quickly gotten off the ground to try to fill the policy vacuum left by Congress to give some guidance to state commissions before they have to start responding to specific utility actions under Title IV. The Edison Electric Institute-NARUC leadership dialogue has already produced some thoughtful work in this regard; and this area is the subject of a Keystone dialogue.

Jurisdictional Problem Areas and Potential Solutions

As regulators respond to Title IV compliance, some real potential problems in these state/federal relationships are briefly identified. A suggestion as to how each problem area might be resolved and a position on the issue will be included, recognizing that there may well be other viable options and that the true issues and interests underlying some of these problems have not yet been fully explored.

Direct Assertion of Authority to Regulate:
Disposition of Allowances as Regulatory Assets

One of the central tenets of Title IV, and indeed, the guiding principle of all the dialogue exercises attempting to provide direction to state commissions, is that state and federal regulation should not be barriers to the effective functioning of an allowance trading market. There is going to be great uncertainty as to how well or how quickly this market will develop. Indeed, much of the emphasis in Congress and in the dialogues mentioned has been upon how to "jump start" this market and to make sure that it develops into something that would be a viable candidate, for instance, for trading on the Chicago Board of Trade. That goal immediately suggests that regulation should be avoided where it is not strictly necessary and that direct regulation in the traditional sense could be very counterproductive to the development of what is supposed to be an unregulated allowance trading market.

It is critical that state regulators recognize how vulnerable the allowance market is to this danger and that the level at which they exercise regulatory oversight of utility compliance with Title IV, and how they do it, needs to be carefully examined. Even if they avoid direct regulation of allowance trading, there is always the danger of unduly affecting that market by the way they regulate utility compliance with the Clean Air Act.

One of the more obvious dangers is that state commissions and the FERC will treat allowances as utility assets whose disposition requires specific regulatory approval, as, for instance, does the disposition of jurisdictional assets for FERC under section 203 of the FPA and under most state commissions' authority. Not only would such regulation do a great deal to kill the development of an allowance trading market; but, even if a market did develop, the overlap between state and federal jurisdiction in this area of regulation would lead to inevitable tensions between the two.

It is recognized, however, that one of the basic tenets underlying the regulatory approach to allowances discussed in the NRRI report, *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program*,[2] is built upon a strong ratepayer interest in the allowance itself. Hence, while legal title is, under Title IV, in the utility, the NRRI report argues that the state commission should recognize the strong *beneficial* interest of ratepayers.

The reasons for this approach are understandable but caution should be used, since, if it is carried too far, it could be highly destructive. Accepting, for the purposes of argument, the legitimacy of the NRRI report's notion, it does not need to translate into direct regulation of the disposition of allowances by state commissions. The beneficial interest of ratepayers can be adequately recognized when it comes to review of the prudence of utility allowance trading in the broader context of Title IV compliance, ideally in the yet broader context of IRP. Essentially, the commission would review the utility's strategic decision to overcomply or undercomply and trade allowances in the context of its overall compliance or IRP strategy and the actual trading of allowances would be an issue only insofar as it is done incompetently, for example at prices less favorable than the relevant market offers. That type of review is very different from direct regulation of allowance trades themselves and would do far less, if any, damage. It would also seem to accommodate the recognition that ratepayers have a beneficial interest in allowances which should not be imprudently traded.

If one does not accept this distinction and insists that the "beneficial interest" of ratepayers in allowances requires some direct control of their disposition, then one would have to look for analogies in traditional ratemaking in order to give the utility the necessary flexibility to trade effectively on the free market, such as "property held for future use." It is doubtful that any such analogies would actually work.

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[2] Kenneth Rose, et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992).

Regulation of Allowance Sales with Power Sale Rates

The distinction between direct regulation of allowance trades and review of their prudence in determining utility rates has even more validity when considering allowance trades in the context of regulation of retail and wholesale power trades. It is doubtful that FERC would have authority, and almost certain that it would not assert it, to regulate allowance trades directly under section 205 of the FPA under which it regulates wholesale power and transmission transactions. Nor is there any authority or interest on the part of state commissions to directly regulate allowance trades as retail power transactions. Allowance trades are not power sales and, anyway, they typically will take place between power producing entities (that is, at the "wholesale level," and not between utilities and end users). There may be some exceptions to this rule to the extent that industrial entities "opt into" the allowance trading scheme.

Of course, the more relevant and more difficult issue with regard to retail and wholesale rates is whether the costs of acquiring allowances are passed on to the customers through rates. In the case of retail rates, that will almost always be the case absence disallowance under prudence review.

At the wholesale level, the matter is less clear. There seem to be a number of options in any wholesale trade transaction: that the seller is responsible for providing allowances with the power sold (and presumably, adjusting the price or at least internalizing it in a competitive context), or that the buyer is expected to acquire the requisite allowances to compensate the seller for the extra generation. Although the latter has the conceptual advantage of giving the buyer the ability to find a lesser cost option of providing the allowances, it seems harder to implement. The strongest conceptual argument seems to require the seller to "unbundle" the sale of the allowances and, perhaps, to give the buyer the option to provide them. This would not only optimize the abilities to acquire allowances between the two parties but it would also create a much larger visible allowance trading market. This could be an important aspect to getting that market going faster in the early years of the Title IV scheme when it is likely to be "thin." The notion of requiring the seller to offer allowances but allowing the buyer to procure them should allay any lingering fears that nonutility generators might get shut out of the power supply market by an inability to obtain allowances.

Unbundling would also give state commissions a better handle on what their utilities are doing in the allowance trading area. Although this should make prudence review more efficient, it also has the danger of state commissions, or even state environmental agencies, attempting to prevent the sales of allowances off a utility system or out of a state because of concerns as to future load growth or local environmental concerns. Given that danger, although FERC could quite easily require "unbundling" of the allowance sale from the wholesale power trade, it will probably want to retain a nexus between the two to preserve its jurisdiction to preempt such state action, if required.

From the viewpoint of FERC's ratemaking, the unbundling would seem to have two advantages. One advantage suggested by Art Garfield of Ohio Edison, is that, in the formative years before firm allowance market prices, it would facilitate efficient power pool operations if the allowance element were isolated as a fixed-price estimate and subsequently "trued up" as the market changes. Moreover, as FERC wholesale pricing moves towards market-based rates, separate prices for the power and allowance sales seems especially appropriate. Again, unbundling will certainly facilitate state commission prudence review of both the wholesale power sales and the allowance sales in different contexts or different parts of an IRP process.

Proposal: FERC, should require unbundling, but preserve the authority to preempt inappropriate state agency actions, and be prepared to use it when needed.

Preemption of State Environmental Agencies

One of the pending concerns as to the working of the allowance trading scheme is that a state environmental agency might seek to prohibit utility sales of allowances (for example to comply with local ambient air quality standards). As suggested, FERC might play a role here, it is also worth putting on the table an equally irreverent notion: that the traditional legal view as to when EPA action preempts state action (typically not when the state imposes a higher environmental standard) may not be applicable to Title IV. The objectives of Title IV are more complex than the typical EPA-enforced statute which seeks only a certain minimum federal standard of compliance and hence does not preempt a higher state requirement. As this is only a pet legal theory and not a proposal, it will not be expanded upon.

Power Pools and FERC Regulation

The challenges that Title IV will pose for FERC regulation will become more serious the more formalized utility coordination arrangements are (that is, the closer we move towards formalized power pools, especially "tight" pools). This is particularly true in this day and age when there is increased competition in the bulk power markets and when FERC's policy is to accommodate and encourage that development. It is important to remember that most power pools are essentially noncompetitive or nonmarket coordination mechanisms. Indeed, many are under increasing tension as their members become competitors in the bulk power markets and may be more inclined to compete for trades in those markets around the pools rather than to use the pool mechanisms.

That tension might be exacerbated by Title IV itself. It is difficult to see how the operation of at least some power pools will not be so affected by Title IV as to necessitate revisions or amendments of pool agreements filed with FERC. For instance, major differences in emission rates between power pool members' units would likely affect pool dispatching orders and cause internal tensions, perhaps necessitating revisions of pool agreements. It is here that some elements in the industry have a real concern that FERC's reaction to requests for amendment could bring the tension between nonmarket coordination mechanisms and the increasingly market-oriented direction of FERC's recent regulation into conflict.

FERC's review of power pool agreements falls under its very broad rate review jurisdiction under sections 205 and 206 of FPA. FERC looks not only at rates themselves but at all the related terms and conditions of power supply and pooling agreements (which are viewed as a species of coordination arrangement). Of particular significance to power pool arrangements, section 205 also proscribes the granting of an "undue preference or advantage" or an "unreasonable difference in rates" in power or transmission arrangements subject to its jurisdiction.

In some major cases in the late 1970s, power pools were challenged before FERC on basically two types of ground: that their membership requirements were so unduly restrictive as to be anticompetitive or discriminatory, and that the failure of the pool to offer certain services, such as firm power sales, was in effect discriminatory and anticompetitive. The upshot of these cases is that, while recognizing the overall legitimacy of and importance of power pools, FERC's regulation also imports some level of antitrust scrutiny and, by the same token, provides some level of implied immunity from the antitrust laws themselves.

The question today and the concern of some electric utilities is that, in the new era of more competitive bulk power markets, there might be a stronger inclination to impose (perhaps at the urging of intervenors) service requirements on the pools, such as transmission access, on the grounds that the pools would otherwise be unduly discriminatory or anticompetitive? However, the prospect of FERC trying to use its authority over power pools to force transmission access seems less and less likely the closer FERC gets to having broad direct statutory authority to mandate access.

However, even the possibility of such an assertion may be enough to deter some power pools from doing what they probably should do if they are to optimize operations in light of Title IV to achieve the lowest possible cost of dispatch and to optimize whatever planning they do (that is, to restructure their pool agreements to take full account of the effect of Title IV on utility production costs).

FERC should send out a clear signal that it encourages such optimization; perhaps, even to the point of requiring each jurisdictional power pool to show that it has fully considered the effects of Title IV and made due adjustments. Of course, if these adjustments can be made without amending the pool agreements on file at FERC, so much the better. However, it is difficult to take full account of Title IV without some sort of amendment to the pool agreement.

If amendment is required, FERC should assure utilities that it will limit the scope of any review strictly to whether the amendments are appropriate to optimize pool operations under Title IV, and not permit inquiry into side issues, such as transmission access.[3] If FERC does not provide this assurance, pools may try to squeeze all necessary amendments into separate "allowance pool" agreements and assert that these are nonjurisdictional. FERC will then be faced with the difficult legal determination as to whether such pools have a sufficient nexus to the power pool to make them jurisdictional and the difficult policy decision as to whether asserting jurisdiction makes sense.

Multistate Holding Company Power Pools

FERC's jurisdiction over these entities derives from its general authority over power pools. However, what distinguishes this situation from power pools of nonaffiliated entities is that an exercise of FERC jurisdiction might trigger the Mississippi doctrine and preempt state prudence review of the Title IV compliance actions of state-jurisdictional holding company generating affiliates, thus raising some of the worst fears of state regulators. For instance, FERC could be forced into the role of adjudicating disputes between states over compliance cost allocations, or over allowance allocations between subsidiaries or divisions of multistate companies operating in different states. The almost classic interstate conflict situation would seem to be presented in a variety of situations:

- states agencies disagreeing over the initial allocation of allowances between utilities in different states that jointly own units,
- disagreements over compliance strategies or over allocations of compliance costs for such units,
- allocations of allowances or compliance costs between holding companies' operating subsidiaries pursuant to system agreements.

There are probably others. Although the state agencies concerned will certainly have an interest in the outcome of all these disputes, it is doubtful that individual state regulation can resolve them under the current regulatory structure, at least, absent some historically unusual comity between states that would permit informal negotiation to work. The

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3 However, FERC could not preclude the ever-present right of a discontented party to file a complaint under section 206.

parallels in some of these scenarios to the system cost allocation issues in the Grand Gulf cases, which led to the Mississippi decision, are obvious. Suffice it to say that these parallels are so threatening to state commissioners that there has been a serious effort to explore state-sponsored regional solutions to these disputes and to keep federal agencies, especially FERC, out of the picture, at least until state-sponsored initiatives have had a reasonable chance to work. Some are going further and starting to talk about the notion of regional regulation that was put so squarely on the table by the National Governors' Association in 1983 and that raised a myriad of other institutional issues.

There is nothing more designed to hinder efficient operation of utility compliance with Title IV than a state/federal jurisdictional squabble similar to that over the Grand Gulf nuclear unit. However, contrary to the belief of some, FERC is not generally looking for opportunities to preempt state regulation. Hence, conflict is potentially avoidable.

Proposal: FERC should exercise extreme caution in exercising its power pool authority over holding companies in the Title IV compliance area in contrast to the case of nonaffiliated power pools, and should do so (or should exercise authority over related allowance pools) only in situations where it can avoid preemptive decisions such as that it made in the Grand Gulf case. That may be easier said than done, but it is a worthwhile policy goal. If state commissions perceive that FERC jurisdiction is being used to avoid their ability to engage in prudence review of utility compliance under Title IV, their inclination to use proactive direct measures to limit utility options in an area where maximum options portend benefit for everyone may be overwhelming, and the results awful.

It should be remembered that most of the potential tensions identified above lead to disputes between states, hence the interest in regional regulation. If FERC finds itself inevitably drawn into them and not able to avoid a Mississippi situation, it should seriously consider using the long underutilized mechanisms of joint boards of, or joint hearings with, the state commissions concerned under sections 209(a) and 209(b) of the FPA. This would be preferable to getting drawn into quasijudicial dispute resolution and, as in Grand Gulf, turning a state versus state dispute very quickly into a vitriolic state versus federal dispute.

Allowance Pools

Ideally, allowance pools should form over geographic regions that do not coincide with power pools but exploit the advantages of diversity between them. Ideally, too, neither FERC nor state commissions should assert jurisdiction to regulate them. As indicated above, FERC may want to do so to discourage power pools from artificially separating their Title IV compliance efforts from other pool operations, but it should do so with greater caution if assertion of its authority might have a Mississippi effect on state prudence review.

Process

There is a broad danger to the efficient operation of the Title IV scheme that really transcends both state commission and FERC regulation: the danger of state legislatures prescribing simplistic compliance "solutions" in advance of, and hence limiting, the utility's considering all options in a systematic, orderly process. This has already occurred in a number of states with a heavy concentration of phase I units. Several have mandated measures to encourage the use of in-state coal. Under the present Title IV structure, there is nothing to stop such assertions. However, if these assertions were to become too numerous and onerous, Congress might step in.

Although state commissions may be relatively powerless to stop such assertions at the outset, they can, through a systematic review of all options, perhaps embarrass legislatures into reconsideration where they have imposed gross inefficiencies. Hence, state commissions should require utilities to file compliance plans that reflect consideration of all feasible options and, where legislatures have imposed higher cost options to meet other objectives, to quantify the added element of cost. This could impose a useful discipline on legislatures in egregious cases.

Conclusion

This paper has been able to do no more than to skim over the surface of what appear to be potential issues that might arise in the interface between economic regulation and Title IV compliance and trading, issues that could prove troublesome and complicate the development of the Title IV allowance trading scheme. The word "potential" is used advisedly, recognizing that some of these issues may not, in fact, arise or might be headed off by sensible preventive action and others that have not even been thought of will surely arise. However, the Title IV scheme is so new, and may be so delicate, that creative speculation as to what problems might arise in the hope of preventing them or being sufficiently prepared for them is critical.

ACID RAIN COMPLIANCE AND COORDINATION OF STATE AND FEDERAL UTILITY REGULATION[1]

by

Robert R. Nordhaus[2]

What Is The Problem?

The Clean Air Act Amendments of 1990 (CAAA)[3] impose new controls on emissions by electric utilities of the two major precursors of acid rain: sulfur dioxide (SO_2) and oxides of nitrogen (NO_x). Utilities, and the utility holding company systems and power pools of which they are members, will be subject to extensive and costly compliance obligations under the new statute. Most of these utilities, utility systems, and power pools are regulated by more than one utility regulatory authority: some by several states; some by a single state and by the Federal Energy Regulatory Commission (FERC); and some by multiple states, by FERC, and by the Securities and Exchange

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[3] 1990 Clean Air Act Amendments, Pub. L. No. 101-549, 104 Stat. 2399 (November 15, 1990).

Commission (SEC). Utility regulators will need to coordinate their policies for ratemaking and for review of acid rain compliance strategies if least-cost solutions are to be implemented without imposing on ratepayers and utility shareholders the costs and risks of inconsistent regulatory determinations. This article outlines the scope of the coordination problem and spells out possible approaches that utility regulators may take in dealing with it.[4]

The 1990 Amendments

The CAAA represent the most significant overhaul of regulation of air pollution in this country since 1970, when the present system of federal controls was established.[5] Key provisions of the CAAA include a new acid rain control program (described below), a graduated system of new controls in areas that have not attained the Clean Air Act's

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[5] The Clean Air Act Amendments of 1970 provided for national ambient air quality standards that had to be met in every area of the country within statutory deadlines (which expired in 1975) (Clean Air Act ("CAA") § 109, 42 U.S.C. § 7409 (1988)); CAA § 110, 42 U.S.C. § 7410 (1988)); and directed EPA to establish new source performance standards (CAA § 111, 42 U.S.C. § 7411 (1988)) and limitations on emissions of hazardous pollutants (CAA § 112, 42 U.S.C. § 7412 (1988)). It also established statutory standards for mobile sources (CAA § 202, 42 U.S.C. § 7521 (1988)).

health-based ambient air quality standards[6], and potential new controls on utility emissions of hazardous air pollutants[7] and greenhouse gases.[8]

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[6] As noted, *supra*, the Clean Air Act Amendments of 1970 were intended to bring every area in the country into compliance with health-based national ambient air quality standards (NAAQS) for ozone, carbon monoxide and certain other pollutants. Twenty years later, approximately one hundred urban areas had not attained the federal standards for ozone and about fifty had not attained the standard for carbon monoxide, H.R. Rep. No. 490, 101st Cong., 2d Sess. 197-8, 204-5 (1990). As a result, the 1990 Amendments imposed a graduated system of additional controls on areas that had not by then attained these standards ("nonattainment areas"). Among the key new requirements for nonattainment areas are more stringent "offset" requirements that apply to any utility proposing to construct a new major stationary source in a nonattainment area. Under these requirements, the utility must purchase offsetting reductions from other sources in the area at least equal to the new emissions the utility is responsible for by reason of construction of the new source. In addition, the EPA in most cases is likely to apply the same control requirements to NO_x as it does on the other ozone precursor, volatile organic compounds (VOC's). As a result, increasingly stringent controls required to be imposed on VOC emissions could, in many areas, also be applied to NO_x emissions. Nonattainment compliance obligations will raise many of the same utility regulatory issues as are raised by the acid rain program.

[7] Title III of the 1990 Amendments (104 Stat. 2531-84) is a new attempt to control hazardous emissions from stationary sources. Under this title, utilities have received a reprieve, of at least three years, from additional regulation, while EPA does a study of the need to apply these new requirements to utility emissions. CAA § 112, 42 U.S.C.A. 7412(n) (West Supp. 1991). After EPA completes its study (which is likely to take about five years), it is possible that extensive new controls, particularly on coal-fired plants, will be necessary in order to comply with the requirements of this title.

[8] Although the 1990 Amendments do not impose any limitations on carbon dioxide (CO_2) emissions, the requirements for monitoring of CO_2 (CAA § 412, 42 U.S.C.A. 7651(k) nt. (West. Supp. 1991)) and the studies the EPA is required to conduct, under CAA § 103, 42 U.S.C.A. § 7403 (West Supp. 1991), may set the stage for future federal regulation of CO_2 emissions and other greenhouse gases. See also, H.R. 776, 102d Cong., 2d Sess. § 1601-6 (1992).

Acid Rain (SO_2)

Title IV of the CAAA imposes an additional layer of control on utility emissions of SO_2 and NO_x, the major precursors of acid rain.[9] The SO_2 controls are designed to achieve a 10-million-ton reduction of utility emissions of SO_2 in two phases, one beginning in 1995, the other beginning in the year 2000.[10] A permanent cap of 8.9 million tons per year is imposed on utility SO_2 emissions in the second phase.[11] Each existing utility generating unit that is fueled by coal, oil, or gas is allocated a fixed number of nationally-tradable emission allowances (an allowance is the right to emit one ton of SO_2 in a calendar year).[12] Utilities are permitted to trade allowances among

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[9] Although rain is naturally acidic, many regions of the United States receive rainfalls which are significantly more acidic than the natural background. This excess acidity results when emissions of SO_2 and NO_x from man's activities react in the atmosphere to form sulfates and nitrates, which can travel for hundreds, and even thousands of miles before reaching ground level as rain, snow, or fog or with particulate matter. The ultimate environmental effects of acid rain are thought to include the acidification of lakes, the killing of fish, the corrosion of buildings, damage to vegetation, and human health impacts. The Clean Air Act which existed prior to the 1990 Amendments regulated SO_2 and NO_x as local air quality problems through the use of State Implementation Plans (SIPs) and New Source Performance Standards (NSPS). Such a localized approach was not well designed to deal with the possibility for long-range transfer of these pollutants, thereby limiting the effectiveness of the Act in dealing with the acid rain problem. The 1990 Amendments address these problems through a national "cap" on SO_2 emissions and other devices. H.R. Rep. No. 490, 101st Cong., 2d Sess., pt. 1, at 356-367 (199).

[10] Phase I requirements can be found at CAA § 404, 42 U.S.C.A. § 7651c (West Supp. 1991); phase II requirements are located at CAA § 405, 42 U.S.C.A. § 7651d (West Supp. 1991).

[11] CAA § 403(a), 42 U.S.C.A. § 7651b(a)(1) (West Supp. 1991).

[12] CAA § 403(b), 42 U.S.C.A. § 7651b(a)(1) (West Supp. 1991).

themselves and with nonutilities,[13] and they may emit any amount of SO_2 (subject to other limitations under the Clean Air Act and state or local air quality laws) as long as they have a number of allowances equal to their emissions in a particular year.[14] New units are not allocated any allowances[15] and must purchase allowances from owners and operators of existing units or from the allowance market. The objective of the allowance system is to achieve the 10-million-ton SO_2 reduction and to ensure cost-effective compliance with the permanent 8.9-million-ton SO_2 cap.[16]

Acid Rain (NO_x)

The NO_x controls under the acid rain program are different from the SO_2 controls in several respects. First, they apply only to coal-fired units.[17] Second, they are not tons-per-year limitations, rather they are emission standards expressed in terms of pounds of NO_x per million British thermal units (mmBtu) of fuel input.[18] Third, although the statute permits averaging of NO_x emissions among units under common

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[13] The 1990 Amendments provide that the owner or operator of a unit not subject to SO_2 controls, under the acid rain program, may choose to opt in and receive allowances based on its emissions in a base period. In addition, nonutilities may buy and sell allowances in the national allowance market. See, 56 *Federal Register* 63, 127 (1991) (to be codified at 40 C.F.R. Part 74).

[14] Under CAA § 404(b), special rules apply to phase II units that are substituted for phase I units during phase I (42 U.S.C. § 7651(b)).

[15] The 1990 Amendments define a new unit as "a unit that commences commercial operation on or after the date of enactment of the Clean Air Act Amendments of 1990;" existing units are defined as "a unit (including units subject to section 111) that commenced commercial operation before the date of enactment of the Clean Air Act Amendments of 1990." CAA § 402, 42 U.S.C.A. § 7651a (West Supp. 1991).

[16] 56 *Federal Register* 63,004-63,005 (1991).

[17] CAA § 407(a), 42 U.S.C.A. § 7651f(a) (West Supp. 1991).

[18] CAA § 407(b), 42 U.S.C.A. § 7651f(b) (West Supp. 1991).

ownership or control, it does not permit national trading similar to that provided for under the SO_2 control program.[19]

Costs of Compliance

Estimates of the cost of control for SO_2 and NO_x under Title IV range from $4 billion to $8 billion per year in phase II.[20] These estimates for the most part assume that the utility industry will be permitted by utility regulators to adopt least-cost compliance strategies, including full utilization of the allowance trading system.[21] If implementation of least-cost compliance strategies is impeded by inconsistent regulatory restrictions imposed by utility regulators, the total compliance cost for the acid rain program may increase substantially.[22]

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[19] CAA § 407(e), 42 U.S.C.A. § 7651f(e) (West Supp. 1991).

[20] For varying Congressional estimates, see 136 *Congressional Record* S16963, S16966 (daily ed. Oct. 27, 1990) (statement of Sen. Baucus); 136 *Congressional Record* S16989 (daily ed. Oct. 27, 1990) (statement of Sen. Nickles); 136 Cong. Rec. S17430 (daily ed. Oct. 27, 1990) (statement of Sen. McClure); 136 *Congressional Record* H12898 (daily ed. Oct. 26, 1990) (statement of Rep. Bruce); 136 *Congressional Record* H12916, H12917, H12919 (daily ed. Oct. 26, 1990) (statement of Rep. Dannemeyer); 136 *Congressional Record* H12942 (daily ed. Oct. 26, 1990) (statement of Rep. Martin).

[21] If one assumes that the allowance trading system is fully operational and that allowance values represent the marginal cost of control of SO_2 emissions on a national basis, then the annual cost of control would be less than the allowance value (dollars per ton) X tons reduction in SO_2. For example, if we assumed (consistent with current projections) that allowance values in year 2000 were $400 a ton and that a 10,000,000-ton reduction were required in that year, then $4 billion would be the upper limit on compliance costs for SO_2.

[22] If there were regulatory impediments to full utilization of the allowance system, then marginal cost of control could exceed allowance costs (because some utilities would be unable to comply by purchasing allowances even though on a cost per ton basis allowance purchases would be cheaper than controlling their units). National compliance costs in that case could exceed allowance value X tons reduced.

This paper focuses on the interaction between the new federal acid rain requirements and state and federal utility regulation, and how utility regulators can coordinate their responses to these environmental requirements.

Implications for Utility Regulation

Federal and State Utility Regulatory Framework

Federal

Electric utility regulation in the United States reflects the intricacies of our federal system. FERC regulates interstate wholesale sales and interstate transmission of electricity under the Federal Power Act (FPA).[23] FERC regulation under the FPA extends not only to rates for interstate wholesale sales and transmission but also to contracts and practices that affect those rates.[24] FERC also has authority over some aspects of corporate regulation of utilities, such as securities issuances, mergers, and disposition of utility assets.[25] FERC's rules under the Public Utility Regulatory Policies Act of 1978 (PURPA)[26] also provide a general framework under which utilities

[23] § 201(b), 16 U.S.C. § 824(b).

[24] §§ 205, 206, 16 U.S.C. §§ 824d, 824e.

[25] See discussion of accompanying note 39.

[26] Section 210 of the Public Utility Regulatory Policies Act of 1978 (codified at 16 U.S.C. § 824a-3).

purchase electricity from cogeneration and renewable energy facilities. FERC does not regulate generation or siting[27] (except for hydroelectric licensing).

The Public Utility Holding Company Act of 1935 (PUHCA),[28] administered by the SEC, regulates public utility holding companies. If a company is part of a public-utility holding company system under PUHCA, it must structure its financing and business activities so as to qualify for one of the various exemptions under section 3 of PUHCA,[29] or it must register with the SEC and submit to extensive corporate regulation and scrutiny of its business and financial affairs, including securities issuances, dividends and capital contributions, sales and acquisitions of utility properties,[30] and interaffiliate transactions and contracts (other than for sale of power[31]). PUHCA also requires any registered holding company or subsidiary thereof to obtain prior SEC approval before acquiring "any securities or utility assets or any other interest in any

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[27] FPA § 201(b)(1), 16 U.S.C. § 824(b)(1) (1988). In commenting on the preemptive effects of the Atomic Energy Act, Justice White declared that "the Federal Government maintains complete control of the safety and 'nuclear' aspects of energy generation; the States exercise their traditional authority over the need for additional generating capacity, the type of generating facilities to be licensed, land use, ratemaking, and the like." Pacific Gas and Elec. Co. v. State Energy Resources Conservation & Dev. Comm'n., 461 U.S. 190, 212, 102 S.Ct. 1713, 1726 (1983).

[28] 15 U.S.C. § 79-79z-6, 49 Stat. 838 (Aug. 26, 1935).

[29] 15 U.S.C. § 79c. PUHCA provides an exemption from registration for a holding company which is: (i) predominantly an intrastate utility holding company, (ii) predominantly a public utility company, (iii) only incidentally a holding company, (iv) temporarily a holding company, or (v) a holding company over foreign utilities. Id.

[30] Registered holding companies are subject to the "integration requirement" of § 11 of PUHCA, which limits each holding company system to a "single integrated public utility system" with only "such other businesses as are reasonably incidental, or economically necessary or appropriate to the operations of such integrated. . .system. 15 U.S.C. § 79k(b)(1).

[31] 17 C.F.R. § 250.80(b).

business."[32] Exempt holding companies must also seek prior SEC approval of certain acquisitions.[33]

State

States regulate retail sales of electricity and related aspects of distribution of electricity to consumers, as well as, siting and operation of generating facilities.[34] States' ability to regulate utility activities otherwise within their jurisdiction is subject to federal constitutional constraints under the preemption doctrine of the Supremacy Clause,[35] under the Commerce Clause,[36] and under the Compact Clause.[37] The preemption doctrine can limit states' actions in areas where Congress has enacted

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[32] PUHCA § 9(a)(1), 15 U.S.C. § 79i(a)(1). Section 10 of PUHCA, 15 U.S.C. § 79(j), identifies various factors that the SEC must examine in determining whether to grant the approval required by section 9(a), including whether: (i) the acquisition will tend toward a detrimental concentration of control of public utility companies, (ii) the compensation paid in connection with the acquisition is reasonable, and (iii) the acquisition will unduly complicate the capital structure of the holding company system of the applicant. PUHCA § 10(b), 15 U.S.C. § 79j(b). In addition, the SEC may not approve the acquisition unless it is satisfied that applicable state laws have been complied with. PUHCA § 10(f), 15 U.S.C. § 79j(f).

[33] Subject to limited exceptions, any person who owns 5 percent or more of any public utility company, must obtain the approval of the SEC (taking into consideration the relevant standards under § 10 of PUHCA, 15 U.S.C. § 79j) pursuant to § 9(a)(2) of PUHCA, 15 U.S.C. § 79i(a)(2), before acquiring 5 percent or more of the securities of another public utility company.

[34] See note 26, *supra*.

[35] U.S. CONST., art. VI, cl. 2.

[36] U.S. CONST., art. I, § 8, cl. 3.

[37] U.S. CONST., art. I, § 10, cl. 3.

statutes which regulate the same subject matter.[38] Under the FPA, FERC is regarded as having exclusive jurisdiction over ratemaking for interstate wholesale sales and interstate transmission of electric power. However, FERC's authority over most other aspects of utility regulation is either shared or concurrent with that of the states (for example, securities issuances,[39] mergers, and acquisitions and sales of jurisdictional assets[40]).

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[38] Louisiana Pub. Ser. Comm'n v. F.C.C., 476 U.S. 355, 368, 106 S.Ct. 1890, 1898 (1986). The Clean Air Act's preemption provisions also bear mention here. The general rule for stationary source regulation under section 116 of the Clean Air Act is that states are free to impose more stringent regulation than Federal requirements and the acid rain control program specifically preserves the authority of state regulators over utilities otherwise within their jurisdiction. 42 U.S.C. § 7416. One area of uncertainty in the statute is with respect to state restrictions on trading of allowances by utilities.

[39] § 203 of the FPA, 16 U.S.C. §§ 824b, 824c.

[40] § 204 of the FPA provides that if a state regulates the security issues of a public utility, then the federal government will not assert jurisdiction in that context. Thus, the state and federal regulatory bodies share authority as one of the two bodies will have exclusive authority at all times. § 204 of the FPA, 16 U.S.C. § 824e (1988). The issue of federal and state authority over the issuance of securities by a public utility was recently addressed in Schneidewind v. ANR Pipeline Co., 108 S.Ct. 1145 (1988). In that case, the Supreme Court struck down a Michigan statute which gave the Michigan Public Service Commission authority to grant approval for the issuance of a long-term security by a public utility transporting natural gas. Finding that the state statute amounted to a direct regulation of the rates and facilities used in the interstate commerce of natural gas, the Supreme Court found that the field that the state of Michigan had regulated was preempted by the Natural Gas Act, even though that Act did not have any provision for Federal regulation of issuance of securities. Schneidewind is inapplicable to electric utility securities regulation because FPA § 204 specifically withholds federal regulation of public utility securities whenever a state regulates them.

In addition, PUHCA's role for state commissions allows them considerable latitude in matters also regulated by the SEC.[41]

The Commerce Clause ensures that states do not disrupt or burden interstate commerce in circumstances where Congress' power remains unexercised. Thus, states may not impose requirements that unduly burden interstate commerce or discriminate against the free flow of commerce.[42]

Finally, the Compact Clause prohibits a state from entering into "an agreement or compact with another state without the consent of Congress."[43] This limitation restricts

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[41] PUHCA was not intended to supplant state regulation, but rather to supplement it by filling the void created by the constitutional disability of the states, as perceived at the time, to regulate and prevent abuses by interstate holding company systems. Alabama Elec. Coop. v. SEC, 353 F.2d 905, 907 (D.C. Cir. 1965), *cert. denied*, 383 U.S. 968 (1966). In some instances PUHCA permits the SEC to defer to the states' authority. For example, PUHCA permits the SEC to exempt a holding company or subsidiary thereof from approval of certain security issuances if state commission approval has been obtained and the purpose of the security issuance is sufficiently limited. PUHCA § 6(b), 15 U.S.C. § 79f(b). Other transactions are subject to the concurrent authority of both the SEC and the states. For example, interaffiliate transactions may be subject to both SEC authority and state review (in some instances as part of a state's general ratemaking authority). See PUHCA § 13, 15 U.S.C. § 79m; N.Y. Pub. Serv. Law. § 110(2). Finally, some states have even enacted legislation which regulates growth and formation of utility holding companies themselves. (For a summary of holding company legislation enacted by the states see Hawes, Utility Holding Companies, § 4 (Clark Boardman 1987).)

[42] The dormant Commerce Clause doctrine prohibits states from enacting statutes or regulations which unduly burden interstate commerce. See Maine v. Taylor, 477 U.S. 131, 138, 106 S.Ct. 2440, 2447 (1986) (holding that upon a finding that a statute discriminates against interstate commerce either on its face or through practical effect, the state must demonstrate that the statute serves a legitimate state purpose and no means other than those currently employed could achieve that purpose).

[43] U.S. CONST., art. I, § 10, cl. 3. In its recent Wyoming v. Oklahoma decision, the Supreme Court reaffirmed that "[W]hen a state statute clearly discriminates against interstate commerce, it will be struck down. . .unless the discrimination is demonstrably justified by a valid factor unrelated to economic protectionism." Wyoming v.Oklahoma, 112 S.Ct. 789, 800 (1992), Citing New Energy Co. of Indiana v. Linbach, 486 U.S. 289, 273, 108 S.Ct. 1803, 1807 (1988) and Maine v. Taylor, 477 U.S. 131, 106 S.Ct. 2440 (1986). Wyoming v. Oklahoma affirmed that the "undue burden" test applies in the energy context.

the extent to which states may enter into interstate agreements that either purport to authorize action within those areas in which states may not act by reason of preemption or the Commerce Clause,[44] or which otherwise enhance the power of the states at the expense of the federal government's authority.[45] However, the Supreme Court has recognized several types of state agreements which will not be considered subject to the

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[44] United States Steel Corp. v. Multistate Tax Commission, 434 U.S. 452, 478, 98 S.Ct. 799, 815 (1978) (stating that "Anytime a state adopts a fiscal or administrative policy that affects the program of a sister state, pressure to modify those programs (of the sister state) may result. Unless that pressure transgresses the bounds of the Commerce Clause. . .it is not clear how our federal structure is implicated." See also Pennsylvania v. Wheeling & Belmont Bridge Co., 59 U.S. 421, 432-33, 15 S.Ct. L.Ed. 435, 437-38 (1855) (holding that a compact between states cannot restrict the power of Congress to regulate commerce among the states).

[45] Virginia v. Tennessee, 148 U.S. 503, 520, 13 S.Ct. 728, 734-35 (1893). The most current formulation of this doctrine was enunciated in United States Steel Corp. v. Multistate Tax Commission, 434 U.S. 452 (1979), where the Supreme Court noted that agreements subject to the Compact Clause are those that directly encroach upon a federal interest. Id. at 470-71.

Also, in Northeast Bancorp, Inc. v. Bd. of Governors of the Fed. Reserve Sys., 472 U.S. 159, 105A S.Ct. 2545 (1985), the Court held that an agreement between New York and Massachusetts to enact similar statutes regarding the purchase of in-state banks by out-of-state bank holding companies was not subject to the Compact Clause since it did not contain the distinguishing characteristics of an interstate compact and, in fact, did not encroach upon federal supremacy in the area of banking regulations. Id. at 175-76, 105 S. Ct. at 2554-55. The indicia of an interstate compact include: whether a joint organization or body has been established to regulate a specific activity, whether enactment of the statutes are conditioned on action by other states, and whether each state is free to modify or repeal its law or regulation unilaterally. Id. at 175, 105 S. Ct. at 2554.

This last indicium, that of allowing states the ability to modify or repeal their law or regulation unilaterally, is of particular significance to interstate agreements involving utility regulation, to the extent action by a state utility commission can be modified or reversed upon a proper showing of change in circumstances or an adequately justified change in policy.

Compact Clause.[46] Interstate agreements allowing for the reciprocal application of regulations or statutes to entities having a presence in both states,[47] enactment of uniform state laws,[48] and multistate cooperation in overseeing the taxation of interstate corporations,[49] have all been recognized as agreements outside of the consent requirements of the Compact Clause. Finally, agreements between a state and the United States are beyond the purview of the Compact Clause.[50]

Potential Jurisdictional Conflicts Under the Existing State/Federal Utility Regulatory Scheme

From the preceding description, it should be clear that there is ample opportunity, even in the absence of an acid rain program, for jurisdictional conflicts, either among states or between state and federal authority. Representative situations are described below.

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[46] For a discussion of informal state cooperation which would not implicate the Compact Clause see Notes, "To Form a More Perfect Union?: Federalism and Informal Interstate Cooperation," 102 *Harv. L. Rev*. 842, 858 (1989).

[47] Northeast Bancorp, Inc. v. Bd. of Governors of the Fed. Reserve Sys., 472 U.S. 159 (1985).

[48] New York v. O'Neill, 359 U.S. 1, 11-12, 79 S. Ct. 564, 571 (1959).

[49] United States Steel Corp. v. Multistate Tax Commission, 434 U.S. 452, 98 S.Ct. 779 (1978).

[50] Blango v. Thornburgh, 942 F.2d 1487, 1490 (10th Cir. 1987). "[W]hile the compact clause prohibits agreements between the states, it does not prohibit agreements between the federal government and the states." See also, United States ex. rel. Gereau v. Henderson, 526 F.2d 889, 894 (5th Cir. 1976).

Single Utility

A single or "stand-alone" utility[51] can be subject to both FERC and state regulation, with FERC regulating its interstate wholesale sales and its transmission for others, and the state regulating retail sales and facilities siting. Similarly, a single utility may operate in several states (PacifiCorp operates an integrated utility system in seven states[52]). Each state can adopt conflicting regulatory policies with respect to the operation of the utility in its state. In addition, there is potential for conflict between each state and FERC with respect to the utility's interstate wholesale sales and interstate transmission.

Holding Companies

Public utility holding companies operating in more than one state are subject to retail rate regulation by each state in which their subsidiaries have utility operations and to FERC regulation of their power sales and transmission transactions among themselves. In addition, under PUHCA there is an overlay of SEC regulation which applies to securities issuances, corporate structure, and contract relations (other than

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[51] A "stand-alone" utility is a utility that is not part of a holding company system or which is the only operating utility in a holding company system.

[52] PacifiCorp operates in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

FERC-jurisdictional sales and transmission) among the companies within a registered holding company system.[53]

Power Pools

Pooling agreements for power pools which include investor-owned utilities that are connected to the interstate grid are subject to FERC regulation, whether or not the boundaries of the pool extend across state lines.[54] This regulation extends not only to regulation of rates for sale of firm power among the members but also to coordination

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[53] PUHCA gives the SEC jurisdiction over certain transaction among registered public utility holding companies and their subsidiaries and affiliates. At the same time, part II of the FPA grants FERC jurisdiction over the transmission and sale of electric power at wholesale in interstate commerce. Conflicts between SEC and FERC jurisdiction are handled under § 318 of the FPA, 16 U.S.C. 825q (1988), which resolves these conflicts by stating that PUHCA shall apply unless the SEC has exempted the affected party from the PUHCA requirement, in which case the FPA will apply. See, Arcadia Ohio v. Ohio Power Co., 111 S.Ct. 415, 417 (1990), which held that § 318 does not establish a broad preemption in favor of the SEC. Instead, Justice Scalia wrote that § 318 operates only in the four areas specifically enumerated in the opinion. 111 S.Ct. at 419-20. The Supreme Court left for the lower court, on remand, the argument that FERC's decision in that case had violated its own governing rules when it determined at a rate proceeding that a power company's cost of coal was unreasonably high. Id. at 422. On remand, the D.C. Circuit found that the PUHCA provision directing the SEC to price goods at cost constrained the FERC from altering that price under its authority to set just and reasonable rates. Ohio Power Co. v. F.E.R.C., 954 F.2d 779, 784 (D.C. Cir. 1992).

[54] The Supreme Court has taken an expansive view of what constitutes interstate commerce for purposes of delimiting the borders of the FPC's jurisdiction. In F.P.C. v. Florida Power & Light, 404 U.S. 453, 92 S.Ct. 637 (1972), the Supreme Court held that Florida Power and Light's indirect connection with out-of-state companies through its participation in an in-state power pool that interconnects and exchanges power with a Georgia utility was sufficient to confer regulatory jurisdiction on the FPC. Id. at 456-59, 92 S.Ct. at 640-42. The FPC's jurisdiction was held to be equally broad in F.P.C. v. So. Cal. Edison Co., 376 U.S. 205, 84 S.Ct. 644 (1964) *reh'g denied*, 377 U.S. 913 (1964) (commonly referred to as the "Colton Case"). There the Supreme Court held that the FPA grants the Commission jurisdiction of all sales of electric energy at wholesale in interstate commerce not expressly exempted by the Act itself. Id. at 215-16, S.Ct. at 651.

transactions and the pass through of fuel and other costs ancillary to production of power sold among pool members.[55] Costs incurred in power purchases from the pool become components of the utility's retail rates and continuing questions arise as to the authority of state regulators to scrutinize particular components of costs that are passed through to utilities by reason of pooling agreements.[56]

Utility Regulatory Issues Under the 1990 Amendments

Almost every aspect of compliance with acid rain requirements of the CAAA raises important and potentially "big-dollar" utility regulatory issues. Moreover, any issue that can be raised before a single utility regulatory agency has the potential to be raised before more than one agency, with the possibility that each different agency will reach a different result on the particular issue. As discussed below, a utility whose regulators adopt inconsistent policies toward acid rain compliance will likely not be able to comply with the Clean Air Act at least cost to its customers or to the country as-a-whole. In

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[55] The D.C. Circuit affirmed FERC's assertion of jurisdiction over deficiency charges ordered by a voluntary pooling agreement, the New England Power Pool (NEPOOL), in Municipalities of Groton, v. F.E.R.C., 587 F.2d 1296, 1301-2 (D.C. Cir. 1978). Similarly, the Supreme Court has held that FERC's exclusive jurisdiction applies not only to rates but also to power allocations that affect wholesale rates. See, Mississippi Power & Light Co. v. Mississippi, 487 U.S. 354, 371 (1988), discussed at note 55, *infra*.

[56] Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 108 S.Ct. 2428 (1988). Mississippi attempted to deny Mississippi Power & Light the right to pass through to retail customers the cost associated with purchasing power pursuant to capacity allocations mandated by FERC. Holding that the State Commission could not alter components of a FERC-mandated capacity allocation, the Supreme Court stated that,

> When FERC sets a rate between a seller of power and a wholesaler-as-buyer, a State may not exercise its undoubted jurisdiction over retail sales to prevent the wholesaler-as-seller from recovering the costs of paying the FERC-approved rate . . ..Such a trapping of costs is prohibited. (Quoting Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 970, 106B S.Ct. 2349, 2359 (1986).)

addition, its shareholders may not be able to recover the full cost of compliance in each jurisdiction.

Planning Conflicts

Traditional utility planning entails matching projected demand with available resources (for example, generating units and purchased power). More recently, utilities have used least-cost planning or integrated resource planning[57] in an attempt to identify the mix of existing new and repowered generation units,[58] purchased power,[59] and "demand-side management"(DSM)[60] that will permit the utility to meet its likely demand (with adequate reserve margins) at least cost to its customers or to society.[61]

Utility planning after enactment of acid rain control is different and a much more complex exercise than it was before the CAAA. If utility acid rain compliance plans are to attain compliance at least cost to the utility and its customers, the utility must

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[57] See generally, Electric Power Research Institute, *Status of Least-Cost Planning in the United States*, EPRI EM-6133, Final Report (Palo Alto, CA: Electric Power Research Institute, 1988); and David Moskovitz, *Profits & Progress Through Least-Cost Planning* (Washington, D.C.: National Association of Regulatory Utility Commissioners, November 1989).

[58] The utility analyzes options for increasing or decreasing the rate of utilization of existing units, retiring those units, "repowering" or reconstructing them to increase their capacity or efficiency, and building new units.

[59] A utility may purchase power from other utilities or from nonutility generators.

[60] DSM is a panoply of rate design, load management, and energy efficiency measures designed to reduce energy use or peak electric demand, or both. Rate design measures include daily or seasonal peak-load pricing, interruptible rates, and elimination of certain promotional rates. Load management includes devices designed to reduce demand during peak periods. Efficiency measures include industrial, commercial, and residential energy conservation, and upgrading efficiency of customer appliances and equipment.

[61] In the late 1980s, twenty-six states required environmental and other "external" costs to be taken into account in a utility's planning process.

undertake extensive analysis of the acid rain compliance options available to it. Such options may involve a range of control technologies,[62] fuel switching,[63] allowance sales and purchases,[64] DSM,[65] and other measures.[66] The evaluation of each option relies on assumptions as to allowance prices, fuel prices, equipment prices, future demand, unit availability, and many other factors.

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[62] Atlantic Electric investigated seventy possible compliance strategies before deciding to install scrubbers at its B.L. England coal-powered Units 1-2. Atlantic Electric also plans to employ scrubbers, or some combination of scrubbers, at the Conemaugh Station facility. The Company hopes that the scrubbers will generate excess emissions allowances for its own use or to be sold on the market. See, "Atlantic Electric Eyes Scrubbers as Phase One Compliance Strategy," *Util. Envtl. Rep.* (April 19, 1991), 14-15.

[63] Tampa Electric Company has chosen to switch to low-sulphur coal to assist in its compliance efforts. See, "TECO to Fuel-Switch for Phase One, Will Make Scrubber Decision by July," *Util. Envtl. Rep.* (March 20, 1992), 12-13. Northern Indiana Public Service Company has chosen to upgrade the electrostatic precipitator at one of its units so as to burn low-sulphur coal more efficiently. The upgrade, likely to be the largest in the power plant's history, will involve internal design changes. Twelve to fourteen companies are presently under contract to do various portions of the project. When completed, the new precipitator will allow the company's Unit-12 to burn a fuel mixture that contains an increased concentration of low-sulphur coal. "NIPSCO Plans Precipitator Upgrades as Part of Michigan City Overhaul," *Util. Envtl. Rep.* (February 21, 1992), 8.

[64] Potomac Electric Power Company has indicated that it plans to purchase an additional 25,000 allowances annually to bring the Chalk Point and Morgantown plants into compliance under phase I. See, "PEPCO Clean Air Plan Combines Allowance Trading, Fuel-Switching and Conservation," *Util. Envtl. Rep.* (May 15, 1992), 7-8.

[65] Potomac Electric Power Company also plans to meet 49 percent of its new demand through conservation by the year 2000 when it plans to have 1,180 MW of DSM programs in place. Id.

[66] Kentucky authorized utilities to collect a monthly "environmental surcharge." This surcharge will be used to pay for scrubber installations that will allow Kentucky utilities to continue to burn high-sulphur coal, thereby protecting local jobs. See, "Kentucky Governor Signs Bill Allowing Surcharge to Recover Scrubber Costs," *Util. Envtl. Rep.* (April 3, 1992), 4-5.

In addition, state decisions on acid rain compliance may factor in policies beyond simply minimizing cost, such as use of locally-produced fuels, employment effects, compliance with other Clean Air Act requirements, and local air quality objectives.

Similarly, differences in timing of regulatory review of compliance plans can produce uncertainty or shareholder risks that make rational planning very difficult. If state A provides for full prior review and approval of compliance plans, and state B has an after-the-fact approval mechanism, there is a risk that changes in utility management's plan to satisfy one regulator will arouse the ire of the other many years down the road.

Other specific issues that can arise are differing policies towards allowance purchases and sales, differing assumptions as to allowance prices, differing policies with respect to use of local fuels, or differing externality calculations for use of coal by utility systems. For example, some states may choose to implement a proposed rate surcharge to allow utilities to recover the costs of acquiring scrubbers, whereas other public utilities commissions might choose to treat these costs as part of a rate base. Another example of a potential state jurisdictional conflict could arise in the context of fuel switching. Some states may prefer not to switch to low-sulfur coal in order to preserve local jobs in the coal industry. In contrast, other states may choose to switch fuels as they would not feel these same costs of increased unemployment.

Inescapably, the assumptions, projections, or policies which are acceptable to one regulatory agency may not be acceptable to the other regulatory agencies which have jurisdiction over a particular utility or utility system's rates and operations. This can have two results. First, utilities are subject to the risk that compliance with one regulator's assumptions or policy preferences will result in disallowance by another regulator, unless they can induce their regulators to adopt common policies.

Second, utilities may be induced to adopt inefficient compliance plans to minimize the risk of disallowance. Utilities or utility systems that operate in more than one state may find that least-cost compliance for the utility as-a-whole will entail adopting expensive compliance strategies in one state (such as installing scrubbers) and adopting an inexpensive compliance strategy in other states (such as fuel switching or retiring a unit). Conflicts will arise as to how to allocate the costs and benefits of such a strategy among states. If the states are unable to agree, the utility may decide to minimize compliance costs in each state, rather than for the system as-a-whole, resulting in higher compliance costs on a system basis.[67]

Operational Conflicts

Regulators' ratemaking and other practices with respect to utility operations also pose considerable potential for conflicting, and ultimately inefficient, regulation. The simplest example is differing policies on allowance valuation. A multistate utility which is regulated in two states which have different methods of valuing, for ratemaking purposes, allowances consumed in generation, would place a utility in an almost impossible bind in determining how to dispatch its units at least cost using its central dispatch system. Similarly, prudence questions could arise for central dispatch systems operated for multiutility power pools or registered holding companies. The value of charges or credits allowed by pool members in the pooling agreement for allowances consumed in generation, may be different than the value assumed by one or more states for purposes of prudence review of the utility's contribution of allowances to the pool. If this occurs, there appears to be no way to operate the pool without imposing losses or conferring windfall gains on ratepayers within particular jurisdictions or on shareholders.

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[67] Another possibility which has been noted is that utilities may be driven to sites in states that offer the most attractive climate from the standpoint of the shareholders. Thus, interstate utilities may bunch their facilities in only certain states. As a result, the citizens of those states will shoulder the burden of the pollution which stems from the construction of the new facilities.

Methods For Dealing With Potential Jurisdictional Conflicts

The potential jurisdictional conflicts described above can be addressed by Congress, either through statutory changes in the FPA[68] or through consent of Congress to interstate compacts.[69] Alternatively, state regulators and FERC can use tools available to them under existing law to reduce the potential for conflict. The tools available under existing law are examined below.

General Approach

As a preliminary matter, it should be noted that the application of federal law, including the Compact Clause, the Commerce Clause, and preemption doctrine, is highly fact-dependent. The factual circumstances attending different utilities' operations and corporate and contractual arrangements will have different legal consequences. In addition, different regulatory issues may require different responses from utilities and regulators in order to eliminate possibilities of jurisdictional conflict. Finally, FERC, the states, and utilities have a great deal of latitude under federal law to structure corporate, contractual and regulatory arrangements. It may, therefore, be possible to reach a workable accommodation of state and federal interests in these circumstances of potential conflict. In this light, utilities and regulators may wish to look at the process described below for assuring policy coordination (or at least, minimizing potential conflict) in connection with Clean Air Act compliance.

The incidence of regulation on each utility, holding company, and power pool needs to be separately reviewed for potential conflicts and for coordination needs. One

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[68] Such a change might give FERC additional supervisory authority over conflicting state decisions respecting acid rain compliance.

[69] Congress could consent to multistate regulatory arrangements under which regional regulation would displace both state retail rate regulation and FERC wholesale rate regulation.

possibility is setting up an ad hoc committee of utility officials and federal and state regulators, on a utility-by-utility basis, to identify issues and to recommend common policies as well as a mechanism for resolving potential conflicts. Once a general course of action is outlined, then there are a number of potential mechanisms that may be used to iron out policy differences and resolve conflicts. They are described below.

Coordination Mechanisms

Informal Consultation

Early informal contacts among regulators can do much to avoid unnecessary conflicts among jurisdictions regulating the same entity. For example, an informed meeting between the representatives of the various regulatory agencies and the utility could help ensure that utility resources are used most efficiently in the case of conflicting regulatory policies regarding allowance purchases and sales. Still, regulators must take care in engaging in such informal consultations during pending proceedings so as to ensure that they do not violate the Administrative Procedure Act's (APA) prohibitions on *ex parte* contact or open meeting laws, if applicable.[70]

Rulemaking

Joint Policy Statements

The federal APA recognizes the role of policy statements (published statements of agency policy which are not binding in each particular case) but which can be prescribed

[70] See note 76, *infra*. The APA's open meeting laws are found at 5 U.S.C. § 552b.

in advance as an indication of general policies that an agency intends to follow.[71] When state law makes similar provision, state regulators or state regulators together with FERC, should consider whether they are able to arrive at and prescribe joint statements of policy on key issues of acid rain compliance. These could include policies on allowance sales and purchases, allowance valuation, timing and scope of prudence reviews, and perhaps common assumptions on planning issues, such as fuel prices and discount rates. Joint policy statements, because they need not be followed in future proceedings, are not likely to be regarded as contravening the Compact Clause. Also, as noted earlier, agreements between a state and the federal government are not subject to the strictures of the Compact Clause.[72]

Uniform Substantive Rules

The state legislative practice of adopting uniform laws is not regarded as presenting Compact Clause objections.[73] There is no reason to believe that uniform

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[71] The APA can be found at 5 U.S.C. §§ 551-559 (1988). What constitutes a statement of policy under the APA has been a topic of academic and judicial discussion for decades and apparently no definitive explication has resulted. See, Kenneth C. Davis, Administrative Law Treatise, § 7:5 (1979 & 1989 Supp.) As the D.C. Circuit stated in Pacific Gas & Elec. Co. v. F.P.C., 506 F.2d 33 (D.C.Cir. 1974):

> A general statement of policy is the outcome of neither a rulemaking nor an adjudication; it is neither a rule nor a precedent but is merely an announcement to the public of the policy which the agency hopes to implement in future rulemakings or adjudications. 506 F.2d at 38.

Current case law hinges on the question of whether the agency statement establishes a "binding norm." Ryder Truck Lines, Inc. v. United States, 716 F.2d 1369, 1377 (11th Cir. 1983), *cert denied*, 466 U.S. 927 (1984).

[72] See note 49, *supra*.

[73] See, Fraser v. Fraser, 415 A.2d 1304, (R.I. 1980) (holding that state legislative enactment of the Uniform Reciprocal Enforcement of Support Act was not a violation of the Compact Clause under the Supreme Court's current interpretation of the Clause). See also, Ivey v. Ayers, 301 S.W. 2d 790, 794-95 (Mo. 1957).

administrative rules should be any more objectionable under the Compact Clause than uniform laws. There may be substantial agreement among regulators on particular ratemaking, accounting, or similar issues. State and federal[74] regulators should examine the possibility of each exercising their independent authority to promulgate uniform rules on key substantive issues, such as accounting practices and ratemaking treatment of allowances.[75]

Coordination of Adjudicatory Proceedings

Adjudicatory proceedings pose more difficulties for joint action than rulemakings because of concerns with *ex parte* constraints,[76] requirements for a record basis for decisions, and open meeting requirements.[77] However, there are several possibilities for coordinating adjudicatory proceedings.

Coordination of Staff Litigation Positions

The first option is to have each regulatory commission's litigation staffs cooperate to submit a common litigation position to each commission involved. If feasible, a joint proceeding should be used (see below). The joint staff litigation position would then be

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[74] In the federal arena, agencies with overlapping or complementary authority over a particular issue have issued joint rules which are promulgated by each agency involved.

[75] Open meeting laws apply in this context as well. See note 76, *infra*.

[76] 5 U.S.C. § 557(d) (1988).

[77] 5 U.S.C. § 552b (1988).

separately considered by each commission, and each commission would issue a decision with or without consultation with the other commissions.[78]

Joint Proceedings

A preferred approach, to the extent permissible under applicable administrative procedure requirements, would be a joint hearing and, if possible, a common decision subscribed to by each commission participating in the proceeding. Section 209(b) of the FPA specifically permits FERC, under its rules, to hold joint hearings with any state commission.[79] FERC rules interpret this provision as authorizing a "concurrent" hearing in which state and federal regulators participate on issues over which each commission has jurisdiction. Each commission makes a separate decision on the record developed in the concurrent hearing. An opportunity for a predecisional conference among the participating commissioners is provided.[80]

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[78] This approach would not trigger the *ex parte* prohibitions of the APA. Section 557(d) prohibits off-the-record communications between the decisional body and interested persons outside the agency. However, if such communications are on the record then they will not invalidate the final adjudicatory decision. (United Airlines v. Civil Aeronautics Board, 309 F.2d 238 (D.C. Cir. 1962). In addition, to the extent FERC is setting rates, the Department of Energy Organization Act ("DOE Act") permits FERC to use trial-type proceedings under 5 U.S.C. 556 and 557 (DOE Act § 403(c)). The APA's *ex parte* rule applies only to proceedings conducted under sections 556 and 557.

The statutory separation of functions under 5 U.S.C. § 554(d) is likely to be inapplicable to utility regulatory proceedings relating to acid rain compliance because of that section's exemptions for ratemaking and initial licensing. State administrative law may differ.

[79] 16 U.S.C. 824h(b). "[T]he Commission is authorized, under such rules and regulations as it shall prescribe, to hold joint hearings with any State commission in connection with any matter with respect to which the Commission is authorized to act."

[80] 18 C.F.R. § 385.1305. FERC also reads the FPA's joint hearing provision as permitting participation by state commissions in an advisory capacity. § 1305(b).

Section 209(b) provides general authorization at the federal level to hold such hearings; however, consideration needs to be given to the possible application of statutory *ex parte* rules and open meeting requirements, which were enacted after section 209 of the FPA.[81] Similar issues would have to be examined at the state level.[82]

Joint Boards Under FPA

Statute and regulations. Another option is the joint board procedure that section 209(a) of the FPA provides.[83] Under this procedure, the Commission may refer a matter to a board composed of a member or members from each state involved. The board has the same powers, duties, and liabilities as a single FERC commissioner would in conducting a hearing. The action of a board has "such force and effect and its proceedings shall be conducted in such manner" as FERC prescribes by regulation.[84] FERC's regulations, in turn, provide that "the force and effect" of a joint board's order will be spelled out in the FERC order referring a matter to a joint board.[85]

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[81] See, notes 73, 74 *supra*. Also, FPA § 209(b) allows the Commission to confer with state commissions regarding rate structures, costs, accounts, charges, practices, and regulations of public utilities under that state's jurisdiction.

[82] Note that § 4-213 of the Uniform Law Commissioners' Model State Administrative Procedure Act specifically permits a member of a multimember panel of presiding officers to communicate with other members of the panel. Model State Admin. Procedure Act § 4-213 (1981).

[83] 16 U.S.C. § 824h(a). "The Commission may refer any matter arising in the administration of this subchapter to a board to be composed of a member or members, as determined by the Commission, from the state or each of the states affected or to be affected by such matter. Any such board shall be vested with the same power and be subject to the same duties and liabilities as in the case of a member of the Commission when designated by the Commission to hold any hearings. The action of such board shall have such force and effect and its proceedings shall be conducted in such manner as the Commission shall by regulations prescribe."

[84] Id.

[85] 18 C.F.R. § 385.1304 (1992).

FERC's regulations (which were originally adopted by the Federal Power Commission in the 1930s) take a very restrictive view of the functions of a joint board. These rules state:

> It is believed that the [joint board procedures] were designed for use in unusual cases, and as a means of relief to the Commission when it might find itself unable to hear and determine the cases before it, in the usual course, without undue delay.[86]

The Commission's position on the role of joint boards appears to be flatly inconsistent with congressional intent. Hearings on the 1935 legislation made it clear that the joint-board provision was "intended as a cooperative provision"[87] that "try[s] to get back so far as possible to the source of the questions that might arise."[88] The 1935 Senate committee report explained:

> This subsection [now FPA § 209(a)] is designed to permit decentralized administration under the general supervision of the Commission by individuals who are acquainted with the situation and the problems of the locality affected by the particular proceeding.[89]

There appears to be no good reason not to use the joint board procedure to meet the coordination needs discussed in this paper. It should be noted that a state's participation in a joint board proceeding (which by its terms relates only to matters arising under the FPA) does not necessarily bind the state acting through its own state

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[86] Id. See Kansas Gas and Electric Co., 31 FERC ¶61,379 at 61,379-80 (1985); Massachusetts v. New England Power Co., 27 FERC ¶61,029 at 61,051 (1984); Kansas State Corp. Comm'n, 25 FERC ¶61,400 (1983).

[87] Hearings on H.R. 5243 (to Amend the Federal Water Power Act) Before the House Comm. on Interstate and Foreign Commerce, 74th Cong., 1st Sess. 519 (1935) (comments of Solicitor Devane).

[88] Id. at 405 (comments of Commissioner Seavey).

[89] H.R. Conf. Rep. No. 621, 74th Cong., 1st Sess. 52 (1935).

commission to adopt parallel policies under state law. However, the agreement of a representative of a state to a particular policy at the federal level is likely to facilitate a similar result at the state level.

<u>How joint boards could operate</u>. The Commission could vest in a joint board the authority to decide particular acid rain compliance issues as related to one or more utilities, and to provide that a unanimous decision would not be reviewed by the Commission, except on very narrow grounds. Nonunanimous decisions would be subject to plenary review by the full Commission. If the board failed to decide a dispute within a specified time, the Commission would revoke its reference of the matter to the joint board, and decide the matter itself. Such a joint board procedure could operate as follows:

(1) FERC through a policy statement or other pronouncement states that it will use joint boards to deal with acid rain compliance issues, on the request of state regulators.

(2) State utility regulators with jurisdiction over a multistate utility or operating utilities that are members of a holding company or power pool petition FERC to establish a joint board to review identified acid rain compliance issues. These issues could include the "wholesale" prudence issues relating to a compliance plan for a utility or holding company or the validity under the FPA of changes in a system agreement or pooling agreement. The states involved could also agree to conduct concurrent hearings on state prudence and retail rate issues arising out of the same compliance plan or system or pooling agreements.

(3) FERC issues an order establishing the joint board. The order would:

   (a) require notice and opportunity for any interested person to participate but would otherwise permit the board to establish its own procedural rules. (*Ex parte* and Sunshine Act issues can be dealt with through open meetings.)

(b) require a board decision within nine months (unless an extension is granted for good cause). The joint board would be discharged of its jurisdiction over the proceeding if it failed to issue a decision within the prescribed period.

(c) provide that a unanimous decision of the board would be subject to "certiorari" type review by the Commission on very narrow grounds. That is, the decision would be reviewed only if two FERC commissioners affirmatively voted to review it, and the scope of review would be limited to grounds of excess of statutory authority, deprivation of constitutional right, or fundamental violation of due process.[90]

(d) provide that a nonunanimous decision would be subject to plenary FERC review, just as a FERC Administrative Law Judge decision is under existing practice.

An approach such as that outlined above would, in the author's view, provide incentives for timely and unanimous resolution of interstate conflicts in utility regulatory policy respecting acid rain compliance. Unanimous decisions by the states are encouraged because such decisions would be subject to the narrowest review permissible under the FPA. Timely decisions are encouraged because delay automatically relegates the matter back to FERC.

FERC Rate Filings

Some issues are so closely tied to FERC's exclusive jurisdiction over rates for interstate wholesale sales and interstate transmission that obtaining state input may require a different approach. Utilities and their state regulators could agree to file pooling or other agreements with FERC that have specific provisions for prior approval

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[90] Consideration should be given to conditioning certiorari review on each state's agreeing not to adopt any decision at the state level that is inconsistent with the joint board decision.

by the affected state commissions. Under this approach, a mechanism for joint approval of key ratemaking components by the state regulators would be incorporated into the FERC-filed rate. If the state regulators could not agree, however, the mechanism would leave the decision on these issues to FERC.[91] For example, a holding company could amend its system agreement to provide that any capital expenditure or operating expense approved by the states, which have retail regulatory jurisdiction over the systems operating companies, would be deemed prudent for purposes of wholesale sales and exchanges among the companies. If properly constructed, such a mechanism would not require congressional authorization,[92] but would require a willingness by the state regulators to subject themselves to such a mechanism.

Conclusion

Because of the wide range of factual situations presented to regulators at this intersection of environmental and utility regulation, and the differing types of regulatory issues that must be resolved, federal and multistate coordination will have to be approached on an ad hoc basis, looking at a variety of tools under existing law for resolving potential conflicts. Although it must be recognized that not all conflicts can be resolved by coordination and agreement, it is possible to assure that unnecessary or unintended differences in state and federal regulatory policies will not impede least-cost compliance with the CAAA.

[91] This mechanism would be akin to a "formula rate." FERC in some circumstances allows utilities to file a rate formula rather than a fixed rate. Once the formula is approved, then rates can change under the formula without the necessity of further rate filings. Typically, a formula rate could take into account various operating factors necessary for the production, sale, and transmission of power for a particular company.

[92] One issue to be resolved, because of delegation concerns, is whether joint approval would be given conclusive or merely presumptive weight.