NRRI 92-6

PUBLIC UTILITY COMMISSION IMPLEMENTATION OF THE CLEAN AIR ACT'S ALLOWANCE TRADING PROGRAM

Kenneth Rose, Ph.D.
Senior Institute Economist

Robert E. Burns, Esq.
Senior Research Specialist

Jay S. Coggins, Ph.D.
Assistant Professor
Department of Agricultural Economics
University of Wisconsin-Madison

Mohammad Harunuzzaman
Research Specialist

Timothy W. Viezer
Graduate Research Associate

THE NATIONAL REGULATORY RESEARCH INSTITUTE
The Ohio State University
1080 Carmack Road
Columbus, Ohio 43210-1002
(614) 292-9404

May 1992

This report was prepared by The National Regulatory Research Institute (NRRI) with funding provided by participating member commissions of the National Association of Regulatory Utility Commissioners (NARUC). The views and opinions of the authors do not necessarily state or reflect the views, opinions, or policies of the NRRI, the NARUC, or NARUC member commissions.

EXECUTIVE SUMMARY

Title IV of the Clean Air Act Amendments of 1990 (CAAA), "Acid Deposition Control," will reduce by the year 2000 annual sulfur dioxide (SO_2) emissions by 10 million tons below the 1980 level, and nitrogen oxides (NO_x) emissions by 2 million tons. Emissions of SO_2 will then be limited to 8.95 million tons per year after 2000. To control SO_2 emissions, Title IV created a new regulatory instrument--an emission allowance or credit--that electric power producers (utilities and others) will be required to possess and expend in order to emit SO_2 into the atmosphere. Electric utilities and others will be allowed to buy and sell these emission allowances in an innovative allowance trading system. Cost estimates of implementing Title IV provisions with a traditional command-and-control type of environmental regulation put the cost 50 to 75 percent higher than with the allowance trading system created by the amendment. Estimates of this potential savings vary from $1 to $3 billion annually.

The allowance trading system can generate these savings because it allows affected sources with relatively high emission control costs to purchase allowances from sources with relatively low control costs. Affected sources unable to install pollution control equipment or other control options for less than the cost of purchasing allowances will be potential allowance buyers. Conversely, sources whose control cost is lower will be potential suppliers. The price of allowances, therefore, will be determined in part by the cost of available alternatives to affected sources.

The Environmental Protection Agency (EPA) will have the primary administrative role in implementing Title IV. However, state public utility commissions and the Federal Energy Regulatory Commission (FERC) will play crucial roles in determining the development and success of the allowance market. The policies and actions that these commissions adopt with regard to their jurisdictional utilities will profoundly influence the cost of compliance and the extent to which the market is used by utilities. Since commissions will have, and in some cases already have had, considerable influence on electric utility compliance decisions, their policies and actions will determine how successful allowance trading will be and, therefore, how much of the projected savings is actually realized.

The CAAA is silent on the type of policies that commissions adopt to implement the amendments. It has been left to each state and FERC to implement the CAAA as they consider appropriate. While the CAAA does not directly mandate commissions to alter their regulatory procedures, the novelty of the allowance system makes it probable that changes will have to be made. The most significant of these changes will likely be development of rules and procedures to accommodate the allowances and the ratemaking treatment of the costs the utility incurs to comply with the CAAA. The ratemaking treatment of allowances in particular is one of the most difficult and complex issues that commissions face with CAAA implementation. This is because there is no exact analogy to allowances and because the allowance system is to be integrated into an already complex system of state and federal regulation.

The regulatory policy options available to commissions are summarized in Table ES-1. The table is intended to provide a graphical representation of the range or spectrum of policy options available to commissions and the advantages and disadvantages of different approaches. Moving along the top of the table, from right to left, is the degree of commission involvement in a utility's planning process. At the top right-hand corner is standard retrospective prudence review; the top left-hand corner is preapproval of all utility compliance plans and expenditures. Between these two extremes are varying degrees of commission review and prior approval.

Corresponding with the degree of commission involvement is the assignment of market risk. Market risk associated with CAAA compliance includes the risk from a change in future allowance or fuel prices. Under a standard prudence review, the utility is only held responsible for decisions that are found to be within its control. Thus, if it was found that inadequate consideration was given to other compliance options, an investment or expense may be disallowed. All prudently incurred costs are passed on to ratepayers.

TABLE ES-1

SUMMARY OF COMMISSION POLICY OPTIONS

Review/Planning Process
(Degree of Commission Involvement)

Preapproval ⟵⟶ Standard Prudence

Pre-Expenditure Approval Approach	Traditional Approach	
Pros: -Reduces regulatory risk -May reduce cost of capital to utility Cons: -Less incentive to minimize cost -Reduces flexibility -More market risk on ratepayers -Considerable amount of resources by commission	Pros: -Ratepayers are protected with retrospective review -Less resources by commission (but still has prudence reviews) Cons: -Moderate incentive to minimize cost -May Increase cost of capital to utility (greater regulatory risk to utility) -Regulatory lag for capital expenditures	Minimum (Cost plus regulation)
Infeasible (Unlikely a commission would assign all risks to ratepayers and at the same time allow market-based incentives.)	**Incentives Approach** Pros: -Greater incentive to minimize cost -Lower compliance cost -Less resources by commission -Less risk to ratepayers -Facilitate allowance market development Cons: -Difficult to implement before allowance market develops	Market-Based Incentives Maximum (All benefits to utility)

⟵ Assignment of Market Risk ⟶

Ratepayers

-Within utility management control: on utility
-Beyond management control: on ratepayers

Since the allowance trading system is market-based, there is an opportunity for commissions to institute a mechanism that will provide utilities an incentive to minimize cost. This has the effect of encouraging utilities to use allowances (both purchasing and selling) and other innovative means to reduce their compliance costs with the added benefit of fostering the development of an efficient allowance market. In Table ES-1, this is represented by the arrow along the right side of the table. At the top is cost-plus regulation with no market-based incentive provided to the utility; that is, all benefits are given to ratepayers. At the bottom of the right side is maximum incentives given to the utility. As with policy choices when moving right to left in the table, there is a diversity of different policy positions when moving from top to bottom. Similar to other policy decisions, commissions are likely to choose some combination rather than one extreme.

The top right-hand box is the policy position consistent with traditional utility regulation; that is, cost-plus (or rate-of-return) regulation with retrospective prudence review. Under this approach, ratepayers would be protected with retrospective review; however, cost-plus regulation may not provide adequate incentives to minimize compliance costs. Moreover, because the allowances are issued at no cost to utilities, this may also provide a distortion or bias in the decisions made by the utility.

Moving to the far left in the table, that is, moving toward preapproval of compliance actions, has been offered as a means to reduce the regulatory risk utilities face. However, this provides the utility with even less incentive to minimize cost since it is intended to reduce the possibility of a retrospective review. This also has the drawback of shifting market risks to ratepayers and may reduce the utility's flexibility to respond to changing market conditions. In addition, this may require considerable commission resources to review the proposed plans and expenditures submitted for approval by the utility.

The lower left-hand box is unlikely to be a feasible policy position for commissions to choose since this would amount to shifting the market risk to ratepayers and then allowing utilities a portion of the benefit from good decisions. It is more likely that commissions will assign the risk of compliance to be commensurate or symmetrical with respect to the rewards and penalties.

As noted, since the allowance system is market-based, an incentives approach (lower right-hand box of Table ES-1) can be developed that uses the market price of allowances as a benchmark standard to evaluate utility compliance costs. Besides providing a greater incentive to minimize compliance cost, there also may be less need for commission resources and less risk to ratepayers than under preapproval. Also, as noted, this has the added benefit of facilitating the development of an efficient allowance market since it encourages utilities to use allowances when appropriate. The disadvantage to this approach is that, so far, there have been too few trades to determine a market price. For this reason commissions may consider temporary means of setting the benchmark until the market develops. Under an incentives approach, commissions would still need to remain vigilant when monitoring compliance costs and keep open the option of retrospective review. As with any incentives system, commissions will have to develop clear and creditable guidelines for utilities with assurances that they will be applied consistently and fairly.

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FOREWORD

Last summer we brought out an interim report on acid rain compliance of timely use for the NARUC Summer Meetings. This publication is a final report on that project. With the evolving developments in implementation of Clean Air Act Amendments of 1990 over the intervening months, this study has new and elaborated content from the last. We have used much of this analysis as a base document in putting on two compliance workshops this spring for EPA/DOE--one in Charlotte and one in St. Louis--for some sixteen state commissions and others. Accordingly, we believe this report advances the public discussions toward a smooth implementation at the state and national levels of this important legislation.

Douglas N. Jones
Director, NRRI
Columbus, Ohio
May 1992

ACKNOWLEDGEMENTS

The authors acknowledge the valuable contribution provided by reviews of an earlier draft of this report. They include: Dwight Alpern, Doug Bohi, John Borrows, Ken Costello, Dan Duann, Doug Jones, Rich Rosen, Elliot Wessler, and Evan White. Also acknowledged are Govindarajan Iyyuni for assisting in preparing data, Dave Wagman for his careful editing, and Marilyn Reiss for her patience and skill in preparing the manuscript.

The authors also thank the participants in five workshops held on this topic by the institute and the participants and organizers of the Keystone Dialogue on State Regulation of Allowance Trading. Any remaining errors are, of course, the authors'.

PART I

OVERVIEW OF THE ALLOWANCE PROGRAM IN THE CLEAN AIR ACT AMENDMENTS OF 1990

CHAPTER 1

SUMMARY AND OVERVIEW OF THE ALLOWANCE PROGRAM IN THE CLEAN AIR ACT AMENDMENTS OF 1990

Title IV of the Clean Air Act Amendments of 1990 (CAAA) created a new regulatory instrument, an emission allowance or credit, that electric power producers (utilities and others) will be required to possess and expend to emit sulfur dioxide (SO_2) into the atmosphere. The emission allowance system created by the CAAA will be grafted onto an already complex system of state and federal electric utility regulation. How state public utility commissions and the Federal Energy Regulatory Commission (FERC) respond to utility compliance actions, including the regulatory treatment of allowances, will greatly affect the decisions that electric utilities under their jurisdiction make to comply with the CAAA and, therefore, the cost of compliance to ratepayers.

Synopsis of Title IV of the Clean Air Act Amendments of 1990

Title IV of the CAAA, "Acid Deposition Control," is intended by the year 2000 to reduce annual sulfur dioxide (SO_2) emissions by 10 million tons below the 1980 level, and nitrogen oxides (NO_x) emissions by 2 million tons below the 1980 level. The intent is to limit emissions of SO_2 to 8.95 million tons. The title also includes provisions to encourage the use of energy conservation, renewable energy (biomass, solar, geothermal, and wind), clean coal alternative technologies, and other pollution control to reduce emissions and "other adverse impacts of energy production and use" (§401(b)).

The reduction in SO_2 will be achieved in two phases. Phase I will require units specifically identified in Table A in Title IV of the CAAA to reduce emissions beginning in 1995. Phase I affected units are units that have emissions greater than 2.5 pounds of SO_2/mmBtu and have a generating capacity greater than 100 megawatts. Phase II affected units are essentially all existing fossil-fueled boilers (including phase I units) that serve an electric generator with a capacity greater than 25 megawatts and all new units. Phase II units will be required to comply by January of 2000.

Title IV stipulates creating a market-based system for trading emission allowances. The allowances will permit the holder to emit one ton of SO_2 that can be either used in the designated year or "banked" (saved) for future use. Existing "affected units" are units that were in operation before the CAAA passed. These units will receive an allocation of allowances based on the actual fossil fuel consumption and unit emissions or the cap specified by the CAAA depending on which is lower. Certain new units specified in the CAAA will also receive an allocation of allowances. New units that begin operation after December 31, 1995 will not be allocated allowances, but will need to acquire allowances to cover their emissions beginning in January 2000. The allowances will be issued and tracked by the U.S. Environmental Protection Agency (EPA).

All affected units will be required to hold sufficient allowances to cover their emissions. Each allowance will be identified as being issued for a specific year. While existing units will be issued allowances only up to the emission requirement (excluding "bonus" allowances), units may exceed this limit if the owner or operator acquires additional allowances. However, all sources are still subject to the National Ambient Air Quality Standard limits (as stipulated in Title I of the CAAA), notwithstanding the number of excess allowances held.

In general, allowance trading is intended to allow sources with relatively low emission control costs to sell their allowances to sources with relatively higher control costs. High-cost sources would buy allowances since the cost of control is more than the price they expect to pay for allowances. In this way the price of allowances is based on the cost of controlling emissions. The price reflects the higher control costs that some utilities and other generators will encounter. Most new generating units (except those with special provisions under the law) will have to purchase allowances from existing sources either directly or through an intermediary. In theory, sources will tend to invest in control options until the marginal cost of emission control equals the expected value of the emission allowances. Overall compliance costs are expected to be lower than command-and-control environmental regulation because of the savings made possible from allowance trading.

Industrial and other sources not covered by Title IV may become affected sources by electing to "opt in" to the allowance system. These sources would be allocated allowances sufficient to cover their current emissions and sources would consider opting-in if their expected emission reduction cost is below the expected allowance price. Their gain would then be the allowance price minus the reduction cost plus any transaction costs.

EPA is required to create special reserves of allowances for special programs mandated by CAAA. In one program, EPA will redistribute the allowances for adopting energy conservation measures or using renewable energy resources to displace emissions. In a second, EPA will provide direct sales of allowances for a fixed price (with priority given to independent power producers) and create an allowance auction system. These reserves will be created by reducing affected sources' initial allocations on a pro rata basis (in proportion to their share of all allowances).

The CAAA establishes a comprehensive permitting system (§408) and requires compliance planning by affected sources. Permits for a period of five years will be issued to affected sources that comply with the provisions of the CAAA. Compliance plans, which will be required to accompany the permit application, will certify that the owner or operator will have sufficient allowances to meet the annual emission requirements of the CAAA.[1] Owners or operators of phase I affected units are required to file a permit application and a compliance plan with EPA for their sources by February 1993. Phase II permits will be issued either by EPA or by states with approved permit programs. Phase II sources must submit permit applications by January 1, 1996 and approved states must issue permits by December 31, 1997. If there is no approved state program, affected sources must submit applications to EPA by July 1, 1996 and

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[1] More detail will be required when special provisions of the CAAA are used as part of a compliance plan. These provisions include units substitution, phase I bonus allowance use, reduced utilization, and unit repowering. These provisions are discussed more fully below.

EPA must issue permits by January 1, 1998. New affected units must submit permit applications two years before either January 1, 2000 or the date when the unit commences operation, whichever is later.

Other provisions of the CAAA include:

- Utilities and others will be allowed to form "allowance pools" where a group of affected sources can take advantage of their different system resources and requirements (§403(d)(2)).
- There will be a penalty of $2,000 per excess ton for sources whose emissions in any year exceed allowances held. These sources will still be required to offset the excess tons in the following year (§411).
- In general, all affected sources will be required to install and operate continuous emissions monitors (CEMS) on each affected unit (multiple units using a single stack will not be required to have unit-specific CEMS). Phase I sources must have CEMS operational by November 15, 1993. Phase II affected sources must have CEMS operational by January 1, 1995. New units must meet the requirements at the start of commercial operation (§412).
- Affected sources will be required to transfer to EPA at the end of each year allowances to cover their SO_2 emissions. EPA will determine in its final rulemaking the length of any grace period for this transfer after the end of the year (EPA has proposed a thirty-day "true-up" period, that is, a transfer deadline of January 30, 40 CFR §77.1) and the method of transfer.
- In general, phase I allowances are based on limiting emissions to 2.5 pounds of SO_2/mmBtu for units larger than 100 megawatts. The allowance allocation for phase I limits are given in Table A in Title IV of the CAAA. Phase II allowances are based on limiting emissions to 1.2 pounds of SO_2/mmBtu for existing utility plants larger than 25 megawatts (§405). This is based on the generating unit's fuel consumption for 1985 through 1987. Utilities can petition the EPA for a different base period if 1985-87

TABLE 1-1

EPA TARGET DATES FOR KEY CAAA PROVISIONS

Action	Date
Allowance Tracking System accounts established for affected units in both phase I and phase II	No later than January 30, 1993
Allowance trading and submittal of transfers to EPA for recordation begins	January 1, 1993
Allocation of allowances from Conservation and Renewable Energy Reserve begins	No earlier than January 1, 1993
Applicants for IPP guarantees for direct sales must apply for financing to construct new units	No later than date of first 1993 auction
EPA Spot and Advance Auctions begin	No later than March 31, 1993
EPA Advance Sales begin	No later than June 1, 1993
EPA Auction Allowances are first usable	January 1, 1995
EPA Sales Allowances are first usable	January 1, 2000
EPA Spot Sales begin	No later than June 1, 2000
EPA may terminate direct sales	No earlier than February 1, 2002
EPA may terminate auctions	No earlier than January 1, 2005
Conservation and Renewable Energy Reserve terminates	No later than January 2, 2010

Source: U.S. Environmental Protection Agency, "Allowance System Proposed Acid Rain Rule," EPA document number 400/1-91/034 (December 1991), 6.

can be shown to be atypical or to correct errors in the data used by EPA (§402(4)).

- EPA is required to develop procedures and requirements for an allowance tracking system for issuing, recording, and tracking allowances. This is to facilitate "an orderly and competitive functioning of the allowance system" (§403(d)).

EPA is required to issue most of the rules implementing the CAAA. Table 1-1 provides deadlines for some of the key provisions of the CAAA and Table 1-2 provides some expected dates for EPA's proposed or final rules for the allowance system. The remainder of this chapter provides more information on the relevant features of the CAAA to state and federal utility regulators and electric utilities.

Phase I

The SO_2 reduction program in Title IV of the CAAA is divided into two phases. Phase I requires that by the beginning of 1995, 110 plants (over 260 units) will be allocated the number of allowances listed in Table A of the CAAA (§404). In general, these units have a capacity of 100 MW or more with emission rates of 2.5 pounds of SO_2 per mmBtu or more (based on the average fossil fuel consumed in the years 1985, 1986, and 1987).

The owner or operator of a phase I unit may substitute one or more of its unaffected units for some or all of an affected unit's emissions reduction (§404(b)). To qualify for the substitution, documentation must be given to EPA that shows total emissions would be reduced the same or more with substitution than the total emissions that would occur from both the original affected unit and substitute unit(s) without substitution. If approved by EPA, both the original and substitute unit(s) would be affected units and subject to the phase I emission requirements. EPA has proposed rules for substitution plans in 40 CFR §72.41.

Affected phase I sources will also be allowed to comply with the requirements of §404 by reducing the use of or shutting down an affected unit (referred to in the CAAA

TABLE 1-2

ALLOWANCE SYSTEM RULE

Subpart	Proposed Rule (Date Published)	Final Rule (Target Date for Publication[1])
Background	December 1991	May 1992
Allocation (phase II)	March 1992	December 1992
Tracking	December 1991	May 1992
Transfers	December 1991	May 1992
Auction and Sales	May 1991	December 1991
Conservation and Renewable Energy Reserve	December 1991	May 1992

Source: U.S. Environmental Protection Agency, "Allowance System Proposed Acid Rain Rule," EPA document number 400/1-91/034 (December 1991), 6.

[1] Other sources (not EPA) have indicated that these dates may be one to two months later than shown here.

as "reducing utilization," §408 (c)(1)(B)). The owner or operator will be required, however, to identify in its compliance plan the source of the generation that will replace the power generated by the reduced output of the affected unit(s). Alternatively, the source can demonstrate that the generation will be supplanted by energy conservation or improved unit efficiency. A unit designated to replace the generation of an affected phase I unit(s) will then be considered (if it is not already) a section 404-affected unit and subject to phase I requirements. EPA has proposed rules for phase I reduced utilization plans in 40 CFR §72.43.

Qualifying phase I units will be allowed to apply for a two-year extension from the phase I deadline to January 1, 1997 (§404(d)). A "qualifying phase I technology" will be one that reduces SO_2 emissions by 90 percent from what would have resulted if the fuel and unit were left unaltered. The allowances needed for the extension will be drawn from a reserve that will equal the reduction of SO_2 emissions projected for 1995 up to a limit of 3.50 million allowances (§404(a)(2)). In addition, adopting these qualifying technologies will make sources eligible for any remaining allowances from this same reserve as an incentive for early phase II reductions (from 1997 through 1999). EPA has proposed that these allowances be allocated on a first-come-first-served basis using a phone-in queuing system (40 CFR §72.501) and has proposed rules for phase I extension plans (40 CFR §72.42).

Since the phase I extension reserve is expected to be oversubscribed, several parties (utilities and the Tennessee Valley Authority) interested in obtaining some of these allowances are considering forming a reserve pool. Under this arrangement the allowances would be allocated on a pro rata basis among the pool participants. Pooling is expected to provide some assurance to the parties that some allowances will be received (in proportion to the level of oversubscription). Taking a chance in the telephone queue could result, they believe, in either no allowances or fewer than anticipated.[2] At this time, it seems likely that some arrangement will be made.

An additional 200,000 allowances will be allocated to units (except for units at three plants) in Illinois, Indiana, and Ohio each year from 1995 to 1999 on a pro rata basis (§404(a)(3)). These allowances are excluded from the calculation of the reserve of incentive allowances. Other provisions are made for units and utility systems that have

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[2] Comments of Stan Garnett, Allegheny Power System, Inc., to the Committee on Electricity of the National Association of Regulatory Utility Commissioners, March 2, 1992.

reduced coal reliance (§404(e)) and for systems that reduced their emission rates (§404(h)). The deadline in this provision was March 1991.

Phase II

In general, beginning January 1, 2000 existing units will be required to reduce their emissions to 1.2 pounds of SO_2 per mmbtu multiplied by their baseline fuel use (1985 through 1987), or hold allowances for the amount they exceed the cap (§405). These existing units will be allocated allowances either up to the cap or, if emissions are less than the cap, their actual emissions plus a 20 percent bonus (in general, coal, oil, and gas-fired units below 1.2 lbs/mmBtu as defined in §§405(d), (e), and (f)). Again, new units (except specific units that commence operation between 1986 and before 1996 listed in Table B (§405(g)) will be required either to purchase allowances or reallocate allowances from the owner or operator's existing units. All affected sources must in each year hold sufficient allowances to cover their emissions.

In addition, special provisions are included for units that primarily use lignite coal (§405(b)(3)), coal or oil-fired units below 75 MW and above 1.2 lbs/mmBtu (§405(c)), and oil and gas-fired units with fuel consumption of less than 10 percent oil (§405(h)).

Other "bonus" allowances will be awarded in phase II in addition to those indicated above. These include 50,000 allowances for the phase I units (based on pro rata share for the unit in Table A of the CAAA, but allocated in phase II) in ten states: Illinois, Indiana, Ohio, Georgia, Alabama, Missouri, Pennsylvania, West Virginia, Kentucky, and Tennessee (exceptions are one unit each in Illinois, Indiana, and Ohio, §405(a)(3)). Also receiving bonus allowances are units with actual 1985 emission rates below 2.5 lbs/mmbtu and capacity factors less than 60 percent in an amount equal to 1.20 lbs/mmBtu multiplied by 50 percent of the difference between the unit's baseline and the unit's fuel consumption at a 60 percent capacity factor (§405(b)(2)); units that converted to coal from oil between 1980 and 1985 located in states with more than 30,000 MW generating capacity (§405(b)(4)); units in high growth states (that is, having population growth in excess of 25 percent between 1980 and 1988 and having an installed generating capacity of more than 30,000 MW in 1988--§405(i)); specific municipally owned power plants (§405(j)); and states with emission rates at or below 0.8 lbs/mmbtu (§406).

The bonus allowances allocated for units below 2.5 lbs/mmbtu and less than 60 percent capacity factor (§405(b)(2) and (c)(4)), coal units below 1.2 lbs/mmbtu (§405(d)(3)(A) and (B)), oil and gas-fired units with less than 10 percent oil consumed (§405(h)(2)), and for states with emission rates at or below 0.80 lbs/mmBtu (§406) will be allocated from a reserve of 530,000 phase II bonus allowances for the years 2000 through 2009. EPA will generate these allowances by deducting a total of 53,000 allowances from the total phase II allowance allocation on a pro rata basis for each of the ten years this reserve will be in operation.

Existing units subject to phase II requirements may comply by repowering the affected unit with a qualifying clean coal technology and receive an extension of the compliance date from January 1, 2000 to December 31, 2003 (§409). The CAAA specifies the qualifying clean coal technologies and describes other technologies that may, as determined by EPA and DOE, also qualify (§402(12)). The owner or operator must demonstrate to the permitting authority by December 31, 1997 the affected unit(s) that will comply with phase II requirements by being repowered with a qualifying clean coal technology. The designated affected unit must be replaced with the repowered unit on the date or before the new unit begins commercial operation. EPA has proposed rules for phase II repowering extension in 40 CFR §72.44.

Conservation and Renewable Energy Bonus Allowances

As mentioned, CAAA creates a conservation and renewable energy reserve of 300,000 allowances that will provide extra or bonus allowances for emissions avoided using a qualified energy conservation measure or a qualified renewable energy source (§404(f)). The reserve was designed to encourage the use of conservation and renewable resources to reduce emissions. A qualified conservation measure is defined as a cost effective measure that promotes the efficient use of electricity. Qualified renewable energy sources are biomass, solar, geothermal, or wind. The specifics of these definitions will be determined by EPA (in consultation with DOE) in their final rulemaking.

EPA has proposed a list of qualified energy conservation measures and renewable energy generation measures for the conservation and renewable energy reserve and supply side measures for the reduced utilization program (Appendix B to §73 of the proposed rules; the main text of the proposed rules for the energy conservation and renewable energy reserve is in 40 CFR §§73.80 through 73.86). In general, qualifying energy conservation measures are demand-side measures that began or will begin operation on or after January 1, 1992 and are *not* supply side measures, load management (unless energy savings can be verified under 40 CFR §73.82), or conservation programs that are exclusively informational or educational. Qualifying renewable energy generation must also begin operation on or after January 1, 1992 and generate electricity directly from the sources indicated above.

The 300,000-allowance conservation and renewable energy reserve will be created by reducing each affected unit's basic phase II allowance allocation on a pro rata basis of 30,000 allowances a year beginning in 2000 and continuing through to 2009. Any remaining allowances in the reserve (after January 2, 2010 when the conservation and renewable energy reserve will terminate) will be allocated on a pro rata basis back to the affected units. EPA has proposed that 60,000 allowances may be set aside from the reserve for renewable energy projects (40 CFR §73.85). This floor will be established if it appears the reserve is about to be depleted without at least 60,000 allowances being used for renewable energy projects. Otherwise allowances will be allocated on a first-come-first-served basis.

Both qualifying energy conservation measures and qualified renewable energy sources must be saving or producing energy between January 1, 1992 and December 31, 2000. Phase I affected sources must apply from 1992 through 1995. Phase II affected sources can apply from 1992 through 2000. EPA has indicated that allowances from this reserve will be awarded on an annual basis beginning no earlier than January 1, 1993.

There are five requirements that an electric utility[3] must meet to qualify for conservation or renewable bonus allowances: (1) the utility must pay for the conservation measure or renewable energy either directly or from another source, (2) the emissions of SO_2 avoided are quantified in accordance with regulations promulgated by EPA, (3) the electric utility has adopted and is implementing a least-cost energy plan that evaluates a range of resources, including new power supplies, energy conservation, and renewable energy sources--the conservation or renewable energy source must be consistent with a plan approved by the jurisdictional state or federal ratemaking authority, (4) DOE must certify that the state jurisdictional commission has established rates and charges that ensure that the net income of the electric utility after implementation is at least as high as the net income would have been if the conservation measure had not been implemented (not required for qualification of renewable energy), and (5) the utility owns or operates at least one affected unit.

An electric utility must provide the following with its application for bonus allowances: (1) identify the qualified energy conservation measure implemented or the qualified renewable energy source used to avoid emissions, (2) calculate the tons of emissions avoided from implementation, and (3) demonstrate that all five of the above requirements have been met. The application is then given to the jurisdictional state or federal agency with ratemaking authority for approval.

The avoided emissions from qualified conservation measures and qualified renewable energy sources are calculated as the product of the kilowatt hours saved or generated in a year and 0.004, divided by 2000--one ton or one allowance = (kWh saved or generated in a year x 0.004)/2000. This calculation is based on the emissions of an average "clean" coal unit that emits at a rate of 0.4 lbs of SO_2/mmBtu.

The CAAA does not specify the method for calculating the energy saved from a qualified conservation program. Thus far, EPA has indicated that its final rules will not

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[3] An electric utility is defined as "any person, [s]tate agency, or [f]ederal agency, which sells electric energy." It is unclear if this definition includes industrial sources (e.g., cogenerators) that sell power and that own or operate an affected unit.

prescribe specific methods for states to follow when verifying their jurisdictional utilities' applications for bonus allowances. However, EPA and others have recognized that a wide variety of methods are available that can lead to significantly different results.[4] Consequently, EPA has created a subcommittee of its Acid Rain Advisory Committee (ARAC) on conservation verification. This subcommittee will advise EPA on the development of conservation verification "protocols" for verifying energy savings from qualifying conservation programs. These protocols would be used for both the energy conservation reserve and the reduced utilization provisions.

It should also be noted that since the reserve is relatively small (the 30,000 to be awarded annually represent only 0.3 percent of the 8.95 million allowances) and with a starting date of January 1, 1992 for qualified programs, most bonus allowances will go to states that already have qualified least-cost plans. States that do not already have a qualified least-cost plan or are not currently in the process of developing such a plan are unlikely to be able to meet these qualifications before the reserve is depleted.

EPA Allowance Sales and Auctions

EPA is also required to create another special reserve of allowances for direct allowance sales and for an allowance auction (§416(b)). The reserve will be created by reducing the phase I affected sources' allocations (on a pro rata basis) by 2.8 percent between 1995 and 1999 and reducing phase II affected sources' allocation by 2.8 percent beginning in 2000. Congress included this reserve as a contingency to provide IPPs access to allowances (by providing direct sales) and to facilitate the development of an

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[4] See for example, *Impact Evaluation of Demand-Side Management Programs, Volume 1: A Guide to Current Practice* (Palo Alto, CA: Electric Power Research Institute, February 1991); Narayan S. Rau, Kenneth Rose, Kenneth W. Costello, and Youssef Hegazy, *Methods to Quantify Energy Savings From Demand-Side Management Programs: A Technical Review* (Columbus, OH: The National Regulatory Research Institute, 1991); and Eric Hirst and John Reed, eds., *Handbook of Evaluation of Utility DSM Programs* (Oak Ridge, TN: Oak Ridge National Laboratory, December 1991).

allowance market for private trading (by creating the auction). As shown in Table 1-2, EPA has issued final rules for the allowance auction and direct sales (40 CFR §73 subpart E).

Direct Sale

A portion of the reserve is to be used for direct sale of allowances, where EPA will offer allowances for $1500 per allowance (to be adjusted by the consumer price index--CPI) giving priority to independent power producers (IPPs) as defined in the CAAA and interpreted by the U.S. Department of Energy (DOE). An IPP proposing construction of a facility that will require allowances before the first EPA allowance auction and that has not received responses to written requests to all affected sources to purchase allowances for $750 is entitled to an EPA written guarantee or "contingency guarantee" of allowances at $1500 per allowance (§416(c)(3)). Since potential lenders and the host utility (for example, in a competitive bid) will most likely either require allowances or a demonstration of an ability to secure them, this written guarantee can be used by the IPP in a bid to supply power and to secure financing for construction of the facility. The CAAA defines an IPP as "any person who owns or operates, in whole or in part, one or more new independent power production facilities." It then defines a "new independent power production facility" as a facility that

> (A) is used for the generation of electric energy, 80 percent or more of which is sold at wholesale;
>
> (B) is nonrecourse project-financed (as such term is defined by the Secretary of Energy within three months of the date of the enactment of the Clean Air Act Amendments of 1990);
>
> (C) does not generate electric energy sold to any affiliate (as defined in section 2(a)(11) of the Public Utility Holding Company Act of 1935) of the facility's owner or operator unless the owner or operator of the facility demonstrates that it cannot obtain allowances from the affiliate; and

(D) is a new unit required to hold allowances under this title.

DOE has proposed (10 CFR §715) that a "nonrecourse project-financed" facility be defined as an IPP that pledges its financed assets and part or all of the revenue from one or more of the power sales contracts covering the affected facility and expressly excludes financing that provides recourse to an electric utility with a retail service territory. However, an equity contribution by a utility in connection with the financing of a facility is not an obligation to repay debt and would therefore not disqualify the financing from being considered nonrecourse.

The proceeds of direct allowance sales will be returned to the affected sources on a pro rata basis. Purchasers are required to pay 50 percent of the total purchase price within six months after the approval of the request to purchase. The remainder will be due before the allowance transfer. Unsold allowances will be transferred to an auction subaccount. The direct sales can be terminated by EPA if less than 20 percent of the allowances available for sale are sold in any two consecutive years (§416(e)(7)). Any remaining allowances will be transferred to the auction subaccount. EPA has indicated that direct sales will not be terminated before February 1, 2002.

Applicants for an IPP written guarantee for direct sales must apply for financing to construct new units no later than the first EPA allowance auction (by March 31, 1993). EPA plans to begin the advanced sales no later than June 1, 1993. These allowances will be usable beginning January 1, 2000. Spot sales will begin no later than June 1, 2000. Table 1-3 shows the number of allowances available for direct sales. This table is taken directly from the CAAA (§416(c) Table 1).

Allowance Auction

An allowance auction will also be conducted with allowances from the 2.8 percent reserve. This auction will be open to anyone interested in participating, will be a sealed bid auction with the sales based on the bid prices, and with no minimum bid. Auction proceeds will be transferred to affected units contributing to the reserve on a pro rata

TABLE 1-3

NUMBER OF ALLOWANCES AVAILABLE FOR DIRECT SALE AT $1,500 PER TON*

Year of Sale	Spot Sale (same year)	Advance Sale
1993 - 1999	-	25,000
2000 and after	25,000	25,000

Source: CAAA Table 1 Sec. 416(c).

*Allowances sold in the spot sale in any year are allowances which may only be used in that year (unless banked for use in a later year). Allowances sold in the advance sale in any year are allowances which may only be used in the seventh year after the year in which they are first offered for sale (unless banked for use in a later year).

basis. Allowances held for auction that were not sold in the auction will be returned to contributing affected sources, also on a pro rata basis. EPA may delegate or contract for auction services. EPA may terminate the auction after January 1, 2005 if less than 20 percent of the allowances available for purchase have been sold in any three consecutive years (§416(f)) after 2002.

Table 1-4 shows the number of allowances available for auction between 1993 and 2000. Any holder of allowances may submit its allowances and specify a minimum price to EPA for sale at auction. These allowances will be sold after the EPA auction is completed. Proceeds will be transferred by the purchaser to the seller; no funds are to be held by an officer or employee of the U.S. government (§416(d)(4)). EPA is required to make public the nature, prices, and results of each auction and record the transfer of

TABLE 1-4

NUMBER OF ALLOWANCES AVAILABLE FOR EPA AUCTION

Year of Sale	Spot Auction* (same year)	Advance Auction*
1993	50,000**	100,000
1994	50,000**	100,000
1995	50,000**	100,000
1996	150,000	100,000
1997	150,000	100,000
1998	150,000	100,000
1999	150,000	100,000
2000	100,000	100,000

Source: CAAA Table 2 Sec. 416(d).

*Allowances sold in the spot auction in any year are allowances which may only be used in that year (unless banked for use in a later year), except as otherwise noted. Allowances sold in the advance auction in any year are allowances which may only be used in the seventh year after the year in which they are first offered for sale (unless banked for use in a later year).

**Available for use only in 1995 unless banked for use in a later year.

allowances. EPA has indicated that spot and advance auctions will begin no later than March 31, 1993. Auction allowances will be usable beginning January 1, 1995.

Allowance Pooling

The CAAA allows affected sources to create "allowance pool" agreements (§403(d)(2)). The Act states that "to insure electric reliability" EPA should not prevent such agreements "that result from their operations, including emergencies and central dispatch." EPA has stated[5] that it interprets this provision of the CAAA as still requiring compliance on a unit-by-unit basis as opposed to an aggregate basis. This is, they believe, consistent with other provisions of the CAAA that specify a unit-by-unit basis. EPA notes that allowances from units in a pool that have a surplus could transfer them during the thirty-day allowance transfer period (between January 1st and January 30th) to units in the pool that required them. Since EPA believes that continuous emissions monitoring will permit utilities to know within hours of the end of the year what action they need to take to comply, the proposed thirty-day transfer period will provide more than sufficient time to conduct transfers within an allowance pool. As a result, EPA does not plan to promulgate specific allowance pooling rules, but rather only insure that other compliance rules do not interfere with private pooling arrangements. This approach relies, EPA believes, on the mechanics of the allowance transfer system and would not require complex compliance planning and permitting requirements (possibly involving several permitting authorities for multi-state units and allowance pools).

Exempt Power Facilities

The acid rain control provisions of the CAAA, while applicable to most fossil-fuel electric generating units, are not applicable to simple combustion turbines, industrial boilers, or process sources, or existing fossil-fuel-fired electric generating units of twenty-five megawatts or less. New cogenerators (beginning construction after the enactment of the CAAA) with less than twenty-five megawatts of capacity and having less than one-third of their potential electric output capacity sold to any utility distribution system will also not be affected utility units which must comply with Title IV of the CAAA

[5] U.S. Environmental Protection Agency, preamble to the proposed rules for the Acid Rain Program: Permits, Allowance Systems, Continuous Emissions Monitoring, and Excess Emissions, 40 CFR §§72, 73, 75, and 77, Office of Air and Radiation, Acid Rain Division, section V(B)(7)(c), 120-21.

(§402(17)(C)). Also, existing qualifying small power producers, qualifying cogeneration facilities, and new independent power production facilities (as defined for the EPA auction and sales reserve discussed above) are exempt from phase II requirements if they meet the requirements of §405(g)(6)(A). This section requires that by the date of enactment, the facility has: (1) an applicable power sales agreement, (2) an electric utility that is required by the state regulatory authority to enter into a power sales agreement with purchase capacity or to enter into arbitration concerning the terms and conditions of the power purchase with the facility, (3) issued a letter of intent or similar instrument committing to purchase power from the facility, or (4) been selected as a winning bidder in a utility competitive bid solicitation.

Election by Additional Sources--Opt-In Provision

Existing and new exempt sources can opt in to the allowance system at their discretion. Allowances issued to units that elect to do this are not considered part of the 8.9-million-ton cap. Industrial boilers or other small existing fossil-fuel units that are not process sources and that elect to opt in are covered by §410(c). The source will be issued allowances based on the lesser of the unit's 1985 actual or allowable emission rate. If the unit did not operate in 1985, the EPA will issue allowances based on the lesser of the actual or allowable emissions rate from a later baseline year. Full credit for decreased allowances can be given these units even if their emission rate is greater than phase I or phase II rates as long as they are unaffected units. Thus, the unit that opts in receives credit for decreased emissions from the baseline year even though it may not do so until years later. A similar program will exist for process sources, however; the CAAA leaves it to EPA to define eligible sources, establish emissions limitations, and determine baseline years.

Opt-in units are subject to the other requirements of the emissions allowance trading provisions, including permitting, penalty, monitoring and record keeping, and enforcement provisions. In addition, allowances for opt-in units that are produced as a result of reduced utilization or shutdown can be transferred or carried forward for use in subsequent years only to the extent that the reduced utilization or shutdown results from the replacement of thermal energy from the opt-in unit, with thermal energy generated by other units subject to the allowance provisions of the CAAA.

Nitrogen Oxides Control

The two-million-ton reduction below 1980 levels by 2000 of nitrogen oxides (NO_x) prescribed by the CAAA is a control requirement, not an allowance-based program. Within eighteen months of enactment, EPA is required to limit NO_x to no more than emissions for tangentially fired boilers to 0.45 pounds/mmBtu (§407(b)(1)(A) and for dry-bottom, wall-fired boilers (other than units applying cell burner technology) to 0.50 pounds/mmBtu (§407(b)(1)(B)). These standards will go into effect after January 1, 1995 and are applicable to all phase I sources. By January 1, 1997, EPA must promulgate emission limitations for wet-bottom wall-fired boilers, cyclones, units applying cell burner technology, and all other types of utility boilers (§407(b)(2)). All affected sources must meet these standards by the phase II deadline date.

Some other NO_x provisions include: (1) by January 1, 1993 EPA must propose, and by January 1, 1994 promulgate, revised new source performance standards (NSPS) for NO_x from all fossil fuel-fired steam generating units (§407(c)); (2) less stringent emission limitations may be authorized if the owner or operator can demonstrate that the applicable emission limitation can not be met using low NO_x burner technology or cannot meet the applicable rate using the technology on which EPA based the limitation; (3) an extension is possible if the required technology is not immediately available (§407(d)); and (4) an owner or operator of two or more units subject to the NO_x provisions may comply based on the average emission rate of all affected units (§407(e)).

It should be noted that EPA has proposed extending by two years the CAAA deadline for states to move forward with nitrogen oxide controls. Some have charged that the proposed change is unlawful. The fear is that the agency's move could result in a serious delay in installing NO_x controls, which in some areas could be essential in meeting clean air standards for ozone. The proposal represents an easing of EPA's previous position, which called on states to prove by November 1992 that NO_x reductions would not improve air quality.

Compliance Planning

The owner or operator will be required to submit a compliance plan certifying that their affected unit(s) will be covered with sufficient allowances to meet the emission requirements of the CAAA (§408(g)).[6] Some public utility commissions now require (and others are likely to require in the future) detailed compliance plans that specify how the utility will comply. In addition to installing pollution control equipment and switching to low sulfur fuel, utilities can retire old capacity, purchase capacity from others, repower an existing plant, redispatch existing units, purchase or sell allowances, bank allowances, or invest in conservation and demand-side management. Most utilities have a wide range of compliance strategies from which to choose.

The cost of each option varies for each of the utility's units and across utilities. For one unit, the least costly means of complying might be to fuel switch, for example, from coal to natural gas. For another, a scrubber might be the lowest-cost option and result in overcompliance, which would free allowances that could be used to bring other units into compliance. A utility should look not only at the cost of compliance on a unit-by-unit basis, but at the cost of compliance for the entire company since trades within a firm will be possible. A utility should also look beyond itself and its system and consider other opportunities for emission allowance trading, perhaps, for example, becoming part of an allowance pool. Finally, a utility should look for allowance trading opportunities nationwide. Compliance planning options and the responsibilities of the state and federal regulators and electric utilities are discussed more fully in Chapter 4.

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[6] As noted earlier, more detailed plans will be required if one or more of the special provisions are used (substitution, phase I extension, reduced utilization, or repowering).

Third-Party Ownership, Purchases, and Sales

The CAAA does not restrict who can purchase, sell, or own allowances. Because an SO_2 emission allowance is essentially fungible, organized exchanges and brokers can play a key role in helping arrange emission allowance trading. Brokers can quickly match buyers and sellers without either one needing to engage in extended contract negotiations. Indeed, it is not even necessary for the buyers and sellers to be identified to each other, although they would need to be identified to the EPA for the purpose of recording the transfers. Once a standard contract is drafted to deal with the risk that Congress might, in the future, partially or fully rescind allowances (see the discussion on allowance ownership rights), brokers can help make the market liquid and lower transaction costs within the market.

The Chicago Board of Trade (CBOT) has requested permission from the Commodity Futures Trading Commission to offer a futures contract for allowances.[7] The New York Mercantile Exchange has proposed offering a similar contract.

Allowance Property Rights

Section 403(b) of the Act states that the EPA will issue regulations that will "permit. . .transfer of allowances prior to. . .issuance." The preallocation transfer of allowances will be deducted from the allowances otherwise allocated to the transferor and added to those of the transferee. For an efficient and effective allowance market to develop, utilities must feel satisfied that allowances represent transferrable property rights. Congress, however, explicitly stated in § 403(f) of the Act that "allowances do not constitute a property right." Rather, §§ 402(3) and 403(f) provide that an allowance is merely a "limited authorization to emit sulfur dioxide." In spite of the bill's explicit

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[7] See Kenneth Rose, "Comments Submitted to the Commodity Futures Trading Commission on the Proposed Chicago Board of Trade Clean Air Futures Contract," November 1991, for a discussion on how futures trading could be used by electric utilities and could benefit ratepayers and electric utilities.

language, allowances are, in fact, a form of property right. What's more, the Congress has held that allowances are assets of the utilities.[8]

The language placed in the CAAA almost certainly reflected two concerns. First, for political reasons, Congress did not want to appear to be creating a property right to pollute. Second, it did not want allowances to be compensable property rights under the Fifth Amendment.

The Fifth Amendment prohibits the taking of private property for public use without just compensation. Rights and benefits created by the federal government, which could have existed independently, may be compensable property. The property interest need not be tangible. However, rights and benefits which could not have existed without government action usually are not compensable property interests, because they are wholly created and defined by federal statute and may be terminated or altered at any time.

Congress intended emissions trading allowances to be treated as a revocable permit or license. Courts have held that where a license or permit is expressly revocable, there can be no reasonable expectation that compensable property interest can arise.[9] However, where a permit is issued that is not expressly revocable, courts have held that a compensable property interest exists.[10] Until a permit or license is actually issued, there is no compensable property interest in the permit.[11]

In the case of emissions allowances, the EPA will begin issuing allowances to phase I plants in 1995 and to all plants in 2000. Until an allowance is issued, it is revocable even if it can be traded. Hence, there is no compensable property interest in the allowance should the Congress or EPA revoke the allowances through legislation.

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8 Report of the House Committee on Energy and Commerce on H.R. 3030 at 366.

9 American International Group v. Iran, 657 F.2d 430, 449 (D.C. Cir. 1981).

10 Scott v. Greenville County, 716 F.2d 1409, 1421 (4th Cir. 1983).

11 Nuclear Transport & Storage, Inc. v. United States, 703 F.Supp. 660,671 (E.D. Tenn. 1988).

Once allowances are issued, however, there may be more than a mere expectation in the allowance: there may be a compensable property right.

Whether emissions trading allowances represent compensable property or not, potential allowance sellers, buyers, and brokers will probably need to design a model contractual provision that copes with the risk that Congress would revoke the allowances either before or after they are issued. Model contractual language would help minimize the transaction costs of transferring allowances and facilitate the goal of economically efficient compliance of CAAA's provisions.

Example of Utility Compliance Options with Allowances

Table 1-5 provides an example of several options available for a hypothetical coal unit. This is a simplified example to provide a means to illustrate a utility's compliance decision process for one unit. In reality the decision is considerably more complex. The utility must consider, among other things, its entire system's compliance, several scenarios of future fuel and allowances prices, the uncertainty associated with capital costs, fuel prices and supply, and regulatory treatment, and the possible offset of emissions with a conservation program. This, of course, introduces a great deal of uncertainty into the compliance planning process.

In this simple example the utility considers five options: (1) purchase allowances, (2) adopt a clean coal technology (CCT), (3) switch to low sulfur coal, (4) repower the unit (with a new boiler, for example), or (5) build a scrubber. Since this hypothetical unit is an existing unit, under the CAAA it will receive 6,623 allowances initially (based on the phase II limit of 1.2 pounds of SO_2 per mmBtu). Given these unit characteristics, the estimated cost of allowances can be factored into the overall cost of compliance for each option. This unit would be an affected unit under phase I of the CAAA since it emits in excess of the 2.5 pounds of SO_2 per mmBtu limit set in phase I of the CAAA; however, only phase II compliance is discussed below.

If the utility chooses not to modify the unit and purchases just the needed allowances, then it would be required to purchase 37,378 allowances, assuming the unit

TABLE 1-5

PHASE II COMPLIANCE EXAMPLE

UNIT	1
AGE	30 years
CAPACITY	200 MW
CAPACITY FACTOR	60%
HEAT RATE	10,500 Btu/kWh
TONS OF SO_2 EMITTED	44,000
INITIAL ALLOWANCE*	6,623

	OPTIONS				
	Allowances	CCT	Switch	Repower	Scrub
SO_2 REMOVED (tons)	-	13,000	37,000	40,000	40,000
UNIT COST OF REMOVAL ($/ton)	-	346	318	422	894
CAPITAL COST ($/kW)	-	14	60	800	200
OPERATING COST (¢/kWh)	-	4	1	-	3
ALLOWANCE NEEDED (tons)	37,378	24,378	378	(2,622)	(2,622)
VALUE OF ALLOWANCE (M$) @ $650/ton	24.30	15.85	0.25	(1.70)	(1.70)
TOTAL COST OF REDUCTION (M$)	0	4.50	11.77	16.88	35.76
NET COST OF COMPLIANCE (M$)	24.30	20.35	12.02	15.18	34.06
INCREMENTAL COST OF COMPLIANCE (¢/kWh)	2.31	1.94	1.14	1.44	3.24

Source: Based on data reported in "Clean Air Response: A Guidebook of Strategies," Electric Power Research Institute (1990) and NRRI calculations.

Note: Quantities in parentheses indicate excess allowances or the amount of overcontrol.

*Total generation $= 200 \text{ MW} * \frac{1{,}000 \text{ kW}}{\text{MW}} * \frac{8{,}760 \text{ h}}{\text{yr}} * 0.6 = 1{,}051{,}200{,}000 \text{ kWh/yr.}$

Total allowance $= (1{,}051{,}200{,}000 \text{ kWh/yr}) * \frac{10{,}500 \text{ Btu}}{\text{kWh}} * \frac{1 \text{ mmBtu}}{10^6 \text{ Btu}} * \frac{1.2 \text{ lbs.}}{\text{mmBtu}} * \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 6{,}623 \text{ tons/yr.}$

operated at the same level. Based on an allowance price of \$650 a ton, this option would have an estimated cost of \$24.3 million (37,378 times \$650) or 2.3¢/kWh. The CCT option will remove 13,000 tons of SO_2, so that 24,378 allowances are needed. Net compliance cost (total cost net of the value of allowances) is then \$20.35 million (\$15.85 million plus \$4.50 million or 1.94¢/kWh). Switching removes 37,000 tons of SO_2, so only 378 allowances are needed to comply with the CAAA. This option has, in this example, the lowest compliance cost at \$12.02 million or 1.14¢/kWh.

The first three options in this example require the utility either to purchase allowances or to use allowances from another unit. However, some options result in the unit being "overcontrolled" or reducing the emissions of the unit below the initial (phase II) allocation. Repowering the unit, for example, removes 40,000 tons and results in overcompliance. Since the utility can sell these generated allowances (the difference between its initial allocation and projected emissions for this option) they have some value to the firm--irrespective of whether the utility chooses to sell them, bank them for future use, or use them at another unit. While repowering has the highest unit capital cost (\$800/kW), it has the second lowest net compliance cost at \$15.18 million or 1.44¢/kWh. Also, the utility can build a scrubber. This frees the same number of allowances as repowering since the emission levels after modification are assumed to be the same (because the scrubber removes the same amount of SO_2). However, in this example, the scrubber is the most expensive option with a net compliance cost of \$34.06 million, or 3.24¢/kWh.

The allowance price of \$650 was chosen for this example because it represents the midpoint of several scenarios that others have projected. Table 1-6 illustrates the effect and importance of the forecasted allowance price on the estimated costs of the options in the above example. When the forecasted price of allowances is \$300, the lowest cost option is to purchase allowances (\$11.21 million and 1.07¢/kWh) while CCT and switching to low sulfur coal become, respectively, the next lowest cost options. When the price of allowances is \$1,000, however, switching again becomes the lowest cost option (\$12.15 million and 1.16¢/kWh), and allowance purchasing becomes the most expensive.

It is interesting to note, however, that the differences between options are relatively small considering the length of time and the total investment involved for the $300 scenario. Four of the options in Table 1-6 (allowance purchase, CCT, switching, and repowering) have estimated incremental costs that vary by only a fraction of a cent. Given the uncertainty associated with any forecast, this difference is negligible. This points to the sensitivity of the optimal option to the actual price of allowances. When the allowance price is low, the difference in costs between options is small. On the other hand, when the allowance price is relatively high the difference in costs become more significant for compliance planning purposes.

TABLE 1-6

EFFECT OF THREE DIFFERENT ALLOWANCE PRICES ON COMPLIANCE COST

	OPTIONS				
Allowance Price $	Allowances	CCT	Switch	Repower	Scrub
	Net Compliance Cost (M$)				
300	11.21	11.81	11.88	16.09	34.97
650	24.30	20.35	12.02	15.18	34.06
1,000	37.38	28.88	12.15	14.26	33.14
	Incremental Compliance Cost (¢/kWh)				
300	1.07	1.12	1.13	1.53	3.33
650	2.31	1.94	1.14	1.44	3.24
1,000	3.56	2.75	1.16	1.36	3.15

Source: NRRI calculation, based on Table 1-5.

CHAPTER 2

DISTRIBUTION OF ALLOWANCES

As discussed, Title IV of the CAAA sets as its primary goal the reduction of annual SO_2 emissions by 10 million tons below 1980 levels by 2000. To achieve these SO_2 reductions, the law requires a two-phase approach involving the trading of annual SO_2 allowances that gradually tightens the restrictions placed on fossil fuel-fired power plants.

Phase I begins in 1995 and affects 110 mostly coal-burning electric utility plants located in twenty-one eastern and midwestern states. The number of phase I units by state, the affected capacity, and the percent of total state capacity are shown in Table 2-1. In the context of the CAAA, a unit is defined as a fossil fuel-fired combustion device. The total SO_2 (from all sources), allocated allowances, and the required reduction are listed in Table 2-2. Figure 2-1 maps the percent of the total SO_2 reduction required for each state. As the tables and figure indicate, the impact is concentrated in the eastern half of the continental United States. Four states, Illinois, Indiana, Missouri, and Ohio, each have over 10 percent of the total SO_2 reductions and together account for over 60 percent of the total required reduction. In Ohio, Indiana, and West Virginia almost 50 percent of each state's total capacity is affected. Again, however, it should be noted that while most of the reduction is located in the eastern half of the United States, in order to add fossil capacity in any state, additional allowances will have to be acquired from their holders.

Phase II, which begins in the year 2000, tightens the annual emissions limits imposed on these large higher emitting plants and also sets restrictions on smaller, cleaner plants fired by coal, oil, and gas. All existing utility units with an output capacity of 25 megawatts or greater and all new utility units will be affected in phase II. The number of phase II units, affected capacity, and the percent of total state capacity are shown in Table 2-3. Total emissions, estimated allowances, and the required reduction for phase II are listed by state in Table 2-4. Figure 2-2 maps the percent of total SO_2

TABLE 2-1

AFFECTED NUMBER OF UNITS AND CAPACITY BY STATE IN PHASE I

State	Affected # of Units	Affected Capacity MW	Affected Capacity % of Total
Alabama	10	3,363	15.7
Florida	5	2,284	6.3
Georgia	19	7,430	34.9
Illinois	17	6,010	16.3
Indiana	37	11,190	48.7
Iowa	6	976	11.2
Kansas	1	158	1.5
Kentucky	17	4,663	26.9
Maryland	6	2,380	20.5
Michigan	2	650	2.7
Minnesota	1	163	1.8
Mississippi	2	750	10.4
Missouri	16	6,546	39.3
New Hampshire	2	459	17.6
New Jersey	2	299	2.0
New York	10	2,407	7.2
Ohio	44	14,562	49.8
Pennsylvania	25	8,088	22.0
Tennessee	19	6,330	34.8
West Virginia	14	7,352	48.8
Wisconsin	13	2,740	24.8
TOTAL	268	88,800	

Source: Based on data from Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1989* (Washington, D.C.: Edison Electric Institute, 1990), Table 3; unpublished 1991 EPA, Acid Rain Division data; Clean Air Act Amendments of 1990, Table A; and authors' computations.

TABLE 2-2

SO_2 EMISSION AND ESTIMATED ALLOWANCE ALLOCATIONS BY STATE (PHASE I)

	Total SO_2 Emissions	Total SO_2 Allowance*		Required SO_2 Reduction**	
	(Tons)	(Tons)	(%)	(Tons)	(%)
Alabama	526,452	230,940	4.05	64,310	1.70
Florida	593,873	133,130	2.34	105,041	2.77
Georgia	989,946	581,600	10.20	234,687	6.20
Illinois	988,669	394,256	6.92	386,818	10.21
Indiana	1,423,835	717,063	12.58	591,475	15.61
Iowa	196,584	40,290	0.71	33,493	0.88
Kansas	131,838	4,220	0.07	3,595	.09
Kentucky	796,652	278,250	4.88	187,255	4.94
Maryland	234,111	139,540	2.45	9,502	0.25
Michigan	427,799	42,340	0.74	16,934	0.45
Minnesota	117,298	4,270	0.07	556	0.01
Mississippi	104,375	54,610	0.96	18,546	0.49
Missouri	953,965	352,990	6.19	425,459	11.23
New Hampshire	72,581	32,190	0.56	13,901	0.37
New Jersey	92,301	20,780	0.36	12,325	0.33
New York	397,517	150,980	2.65	18,260	0.48
Ohio	2,243,991	960,200	16.85	946,940	25.00
Pennsylvania	1,154,185	534,140	9.37	130,523	3.45
Tennessee	806,882	386,430	6.78	254,824	6.73
West Virginia	942,784	497,870	8.74	246,885	6.52
Wisconsin	381,184	143,380	2.52	86,817	2.29
TOTAL	16,158,813	5,699,469		3,788,146	

Source: Clean Air Act Amendments of 1990, Table A; unpublished 1991 EPA data, Acid Rain Division; and authors' computations.

* Total allowances are based on Table A of the CAAA plus the pro rata share for Illinois, Indiana, and Ohio of the 200,000 bonus allowances. However, this does not represent the actual allowances that will be received by the affected sources because of the other bonus allowances.

**Total phase I required SO_2 reduction based on units in states that exceed the 2.5 pounds of SO_2/mmBtu requirement for units over 100 MW.

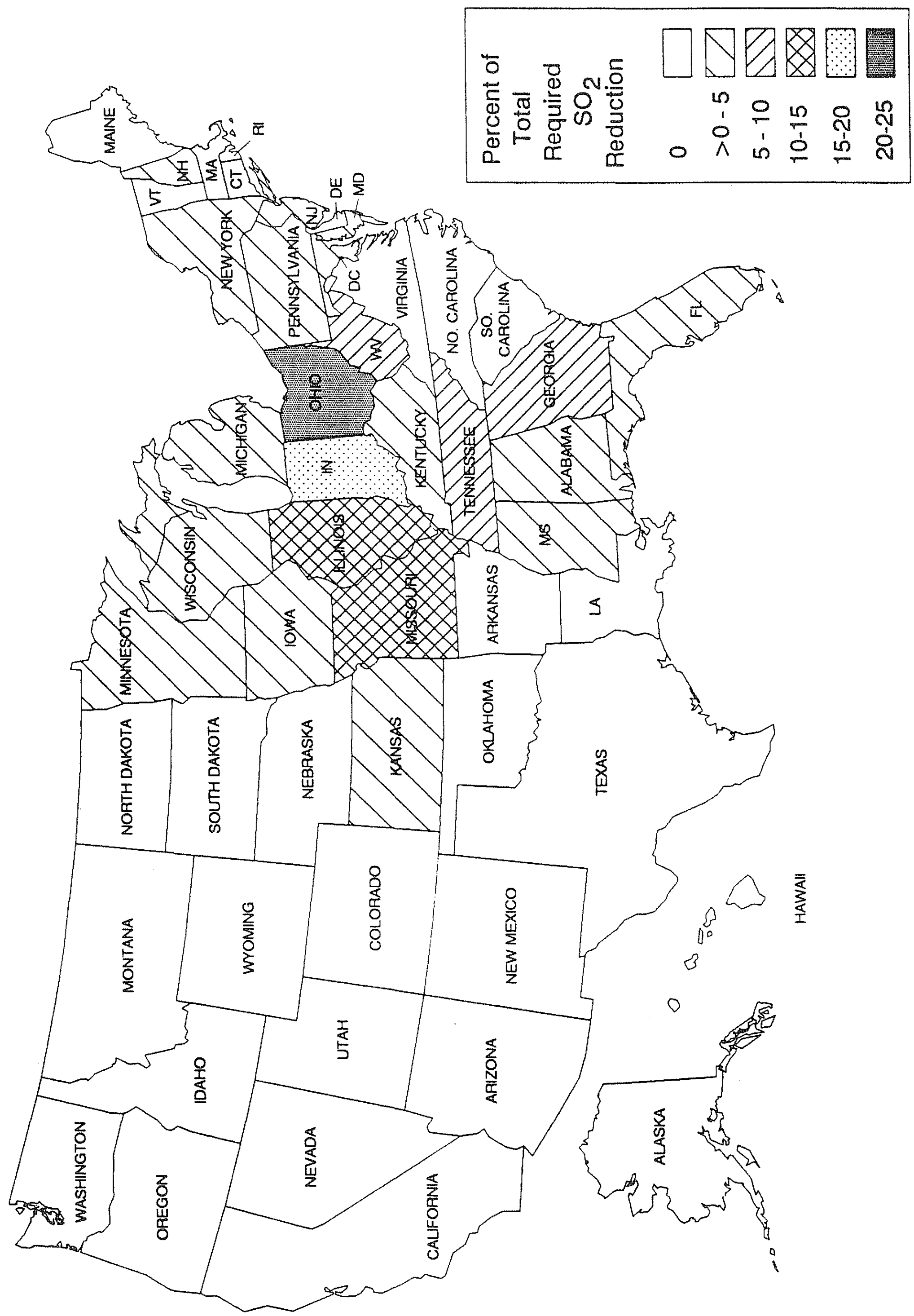

Fig. 2-1. Phase I SO_2 reduction by state--percent of total.

TABLE 2-3

AFFECTED NUMBER OF UNITS AND CAPACITY BY STATE IN PHASE II

State	Affected # of Units*	Affected Capacity MW	Affected Capacity % of Total
Alabama	28	6,490	30.4
Delaware	10	619	27.1
Florida	27	7,581	21.0
Georgia	34	9,755	45.9
Illinois	40	9,016	24.4
Indiana	67	13,534	58.9
Iowa	32	2,861	32.7
Kansas	8	1,381	12.8
Kentucky	31	8,120	46.8
Maine	4	241	9.9
Maryland	15	4,317	37.1
Massachusetts	15	3,911	38.8
Michigan	44	8,497	35.2
Minnesota	18	2,097	22.7
Mississippi	2	750	10.4
Missouri	33	9,721	58.3
Montana	1	191	3.9
Nebraska	2	337	5.9
New Hampshire	8	1,073	41.2
New Jersey	7	1,664	11.1
New York	47	6,739	20.2
North Carolina	38	10,743	51.4
North Dakota	6	1,185	25.3
Ohio	116	21,791	74.5
Pennsylvania	61	15,774	42.9
Rhode Island	4	179	65.1
South Carolina	21	3,873	22.2
South Dakota	1	456	16.7
Tennessee	33	9,780	53.7
Texas	8	4,981	7.5
Virginia	18	3,501	24.0
Washington	2	1,460	6.2
West Virginia	27	9,358	62.1
Wisconsin	50	5,388	48.7
Wyoming	3	743	12.0
TOTAL	861	188,107	

Source: Based on data from Edison Electric Institute; unpublished 1991 EPA, Acid Rain Division data; and authors' computations.

* For purposes of this table, affected units are units that exceed the phase II limit of 1.2 pounds of SO_2/mmBtu. As explained in Chapter 1, nearly all existing fossil-fueled units larger than 25 MW are "affected units" under Title IV (over 2,700 units). In the context of the CAAA, a unit is defined as a fossil fuel-fired combustion device.

TABLE 2-4

SO_2 EMISSION AND ESTIMATED ALLOWANCE ALLOCATIONS BY STATE (PHASE II)

State	Total SO_2 Emissions (Tons)	Total SO_2 Allowance (Tons)	Total SO_2 Allowance (%)	Required SO_2 Reduction* (Tons)	Required SO_2 Reduction* (%)
Alabama	526,452	305,510	3.63	239,294	2.93
Arizona	104,881	125,858	1.49	0	0.00
Arkansas	73,609	88,331	1.05	0	0.00
California	4,701	5,633	0.07	0	0.00
Colorado	83,336	97,872	1.16	0	0.00
Connecticut	60,877	73,049	0.87	0	0.00
Delaware	68,886	55,557	0.66	16,580	0.20
District of Columbia	1,345	1,614	0.02	0	0.00
Florida	593,873	372,171	4.42	251,511	3.08
Georgia	989,946	398,268	4.73	594,756	7.27
Illinois	988,669	374,540	4.45	631,421	7.72
Indiana	1,423,835	450,899	5.36	978,186	11.97
Iowa	196,584	115,831	1.38	88,735	1.09
Kansas	131,838	114,180	1.36	31,447	0.38
Kentucky	796,652	373,776	4.44	448,574	5.49
Louisiana	66,489	79,784	0.95	0	0.00
Maine	12,225	11,624	0.14	1,438	0.02
Maryland	234,111	133,797	1.59	104,649	1.28
Massachusetts	254,063	172,642	2.05	88,828	1.09
Michigan	427,799	374,293	4.45	68,667	0.84
Minnesota	117,298	86,510	1.03	34,055	0.42
Mississippi	104,375	61,832	0.73	46,943	0.57
Missouri	953,965	273,950	3.25	669,694	8.19
Montana	16,797	17,074	0.20	1,641	0.02

TABLE 2-4--Continued

State	Total SO_2 Emissions (Tons)	Total SO_2 Allowance (Tons)	(%)	Required SO_2 Reduction* (Tons)	(%)
Nebraska	46,922	55,049	0.65	222	0.00
Nevada	49,698	59,637	0.71	0	0.00
New Hampshire	72,581	32,568	0.39	40,013	0.49
New Jersey	92,301	60,165	0.71	31,706	0.39
New Mexico	71,726	85,567	1.02	0	0.00
New York	397,517	225,783	2.68	180,338	2.21
North Carolina	331,535	290,027	3.44	50,011	0.61
North Dakota	131,958	133,312	1.58	15,231	0.19
Ohio	2,243,991	672,048	7.98	1,570,506	19.21
Oklahoma	87,689	105,227	1.25	0	0.00
Oregon	898	1,078	0.01	0	0.00
Pennsylvania	1,154,185	564,988	6.71	598,333	7.32
Rhode Island	3,339	3,013	0.04	111	0.00
South Carolina	160,671	106,822	1.27	56,547	0.69
South Dakota	25,157	12,504	0.15	12,158	0.15
Tennessee	806,882	298,592	3.55	508,290	6.22
Texas	570,769	591,020	7.02	40,306	0.49
Utah	22,595	26,958	0.32	0	0.00
Vermont	155	25	0.00	0	0.00
Virginia	142,170	126,839	1.51	20,463	0.25
Washington	62,826	45,037	0.53	17,789	0.22
West Virginia	942,784	445,628	5.29	524,183	6.41
Wisconsin	381,184	172,448	2.05	211,266	2.58
Wyoming	126,674	140,398	1.67	1,448	0.02
TOTAL	16,158,813	8,419,328		8,175,340	

Source: Unpublished 1991 EPA data, Acid Rain Division; and authors' computations.

* Required SO_2 reduction is based on the number of units that exceed the phase II 1.2 pounds of SO_2/mmBtu requirement. Some units, however, will receive more allowances than needed. For this reason column 4 is *not* the difference between columns 1 and 2.

Fig. 2-2. Phase II SO_2 reduction by state--percent of total.

reduction required for each state. Almost one-third of the affected units and megawatt capacity are located in four states: Indiana, North Carolina, Ohio, and Pennsylvania. Seven states have over 50 percent of their total capacity affected in phase II: Indiana, Missouri, North Carolina, Ohio, Rhode Island, Tennessee, and West Virginia. Five more states have between 40 and 50 percent of their capacity affected: Georgia, Kentucky, New Hampshire, Pennsylvania, and Wisconsin. Indiana and Ohio again have the largest required reductions in emissions: 12.0 percent and 19.2 percent, respectively. The largest shares of allowances, each over 5 percent of the nation's total, go to Texas, Ohio, Pennsylvania, West Virginia, and Indiana.

The allocation of allowances is made to the owner, operator, or designated representative of an individual utility. Therefore, it is important to consider the concentration of allowances at the firm level. The effective functioning of markets is predicated upon competition, since the presence of market power could decrease the efficiency of the allowance trading market (discussed in more detail in Chapter 3). Tables 2-5 and 2-6 and Appendix B indicate that while the concentration of allowance holdings by a few firms appears substantial, these shares are reduced significantly in phase II.[1]

Although allowances will be distributed to individual operating companies, the decisions on how to use these allowances will depend on the operating agreement of the particular holding company. However, in order to indicate the possible presence of market power, the individual affiliate holdings of allowances were aggregated into the respective utility holding company. In phase I the twenty largest holdings of allowances account for about 80 percent of the total. By phase II this aggregate (with different members) is reduced to a little over half of the total emissions allowances available.

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[1] It should be noted that what is aggregated here is the total allowance allocation, not the allowances available for sale. These discretionary allowances would be useful also for determining market power, but at this time the numbers of allowances that will be retained for each utility's system use is not yet available. Moreover, as will be shown in the next chapter, the price of allowances and the utility's control-cost will determine the number of allowances made available for sale or purchased by a utility (and industrials that opt-in).

TABLE 2-5

TOP 20 COMPANY SHARES OF PHASE I EMISSION ALLOWANCES

Top 20 Companies	Phase I Allowances	Share of Total (%)
Southern Company**	821,160	14.4
American Electric Power**	557,717	9.8
Tennessee Valley Authority	552,640	9.7
Allegheny Power System Incorporated**	376,320	6.6
Public Service Company of Indiana	320,668	5.6
Union Electric Company	200,330	3.5
General Public Utilities Corporation**	191,340	3.4
Ohio Edison Company*	177,626	3.1
Illinois Power Company	175,938	3.1
Pennsylvania Power & Light Company	158,370	2.8
Centerior Energy Corporation	150,763	2.6
Dominion Resources Incorporated	121,730	2.1
Indiana-Kentucky Electric Corporation	120,190	2.1
Potomac Electric Power Company	119,980	2.1
IPALCO Enterprises Incorporated	97,768	1.7
Long Island Lighting Company	93,200	1.6
Ohio Valley Electric Corporation	93,200	1.6
Cincinnati Gas & Electric Company*	93,018	1.6
Associated Electric Cooperative Incorporated	90,360	1.6
TECO Energy Incorporated	82,250	1.4
Total Top 20	4,594,568	80.4

Source: Unpublished 1991 EPA, Acid Rain Division data and authors' computations.

* Multistate holding company.
** Multistate holding company registered under the PUHCA.

TABLE 2-6

TOP 20 COMPANY SHARES OF PHASE II EMISSION ALLOWANCES

Top 20 Companies	Phase II Allowances	Share of Total (%)
Southern Company**	712,792	8.5
American Electric Power**	503,796	6.0
Tennessee Valley Authority	459,401	5.5
Texas Utilities Company	268,861	3.2
General Public Utilities Corporation**	238,461	2.8
Detroit Edison Company	227,061	2.7
Allegheny Power System Incorporated**	217,946	2.6
PacifiCorp	201,305	2.4
Pennsylvania Power & Light Company	171,150	2.0
Ohio Edison Company	155,719	1.8
Duke Power Company	151,748	1.8
Public Service Company of Indiana	149,491	1.8
Carolina Power & Light Company	145,611	1.7
Dominion Resources Incorporated	145,143	1.7
Commonwealth Edison Company*	136,477	1.6
Union Electric Company	134,946	1.6
Central and South West Corporation**	131,387	1.6
Florida Progress Corporation	118,310	1.4
Centerior Energy Corp.	110,873	1.3
DPL Incorporated	107,362	1.3
Total Top 20	4,487,840	53.3

Source: Unpublished 1991 EPA, Acid Rain Division data and authors' computations.

* Multistate holding company.
** Multistate holding company registered under the PUHCA.

The Southern Company, American Electric Power, the Tennessee Valley Authority, and Allegheny Power System jointly account for over 40 percent of the market in phase I. By phase II this concentration is reduced to one-fifth of the market.

Market concentration is an important measure of market power. Several indices of market share are available. The best known is the Herfindahl-Hirshman Index (HHI) adopted by the U.S. Department of Justice as a standard for implementing antitrust policies in approving mergers.[2] In phase I the HHI value is 0.058 and in phase II it is 0.024. This suggests that the concentration of market power will not be a problem in either phase. As the market develops, however, allowances could become more concentrated among utilities that have more discretionary allowances (that is, more allowances available for sale). If this situation were to develop then the price of allowances could be affected. State commission and FERC action on compliance costs and allowances could lead to this outcome to the extent they influence the overcontrol and banking decisions of an industry. But the conjecture here is that concentration is sufficiently low to make this also unlikely.

It should be acknowledged that there is a school of thought on antitrust matters that would question the validity of HHI. This "new industrial organization" envisions the existence of markets where, even though incumbent firms have increasing returns to scale or high market shares, the market may, under certain conditions, be "perfectly

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[2] The HHI is a compound index that uses both the number of sellers in the market as well as their sizes. It is given by

$$HHI = \sum_{i=1}^{n} s_i^2$$

where s_1 equals the percentage share or fraction of the market accounted for the ith firm. The reciprocal of the HHI equals the equivalent number of sellers of equal size. As an example, an HHI value of 0.125 is equivalent to eight sellers having equal market shares. HHI values close to one reflect high concentration (and market power) and values close to zero reflect low concentration.

contestable." In this case, potential entry and the resulting price competition are sufficiently effective to discipline existing firms. Hence, even a highly concentrated industry may be quite competitive. Again, the HHI shows that even without this consideration, concentration in the emission allowance market falls substantially from phase I to phase II and is not likely to be a significant problem.

CHAPTER 3

ECONOMIC RATIONALE FOR AN EMISSION ALLOWANCE TRADING PROGRAM

The basic assumption behind the economic model of allowance trading is that managers of firms are better at solving pollution abatement problems than government overseers. This is because first, firms know more than an environmental regulator about their own operations and second, because the profit motive, rather than direct government mandate of compliance decisions, may be more effective at minimizing emission control costs. The allowance trading program in the CAAA is designed to provide firms with an incentive to make good choices about how to reduce emissions by allowing the firm to reduce compliance cost and profit from trading. By harnessing this powerful incentive, the argument goes, and placing the decision of how to achieve a given environmental goal in the hands of those who pollute, the overall cost of compliance can be lower than with command-and-control measures. This idea as it pertains to pollution control, now nearly sixty years old, has become a part of the intellectual mainstream of economics.[1]

Intuitively, the idea has a plausible feel to it. There are many emitting sources out there, each with a different set of circumstances (fuel type availability, generation mix, control strategies, and so on). Some will find it less expensive to cut back their sulfur emissions than others. If a system can be devised to get relatively low-cost sources to reduce emissions, while those for whom cutting back a comparable amount is relatively costly continue to operate as before (except that now they must buy some allowances), then overall compliance costs should be minimized. From the perspective of each plant, then the firm is given a choice of how to comply with a particular environmental standard. If the price of an allowance is lower than the per-ton cost of

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[1] The first version of the marketable permit argument is evidently that found in A. C. Pigou, *The Economics of Welfare*, 4th edition (London: MacMillan and Co., 1932).

reducing emissions (such as installing a scrubber or switching fuel), then the utility should buy allowances. Otherwise, the utility should reduce emissions and sell any excess allowances at the market price or bank them for future use.

Benefits of Allowance Trading

The intended benefits of emission allowance trading over a command-and-control type of environmental regulation can be illustrated graphically if several simplifying assumptions are made.[2] Assume that there are two power plants that each emit 15,000 tons of SO_2 per year for total emission of 30,000 tons. Assume also that there is no economic or profit regulator. In this example, the environmental regulator decides that emissions should be cut by half to 15,000 total tons (it is not important for this discussion to discuss how this was determined). Figure 3-1 illustrates the effect of a proportional reduction in emissions, where each plant is required to reduce its emissions to seven-and-one-half tons per year. MC_1 and MC_2 are the marginal emissions reduction costs for plants 1 and 2 respectively. The origin for plant 1 is the lower left-hand corner of the diagram and the origin for plant 2 is the lower right-hand corner. Assume that the marginal cost of reduction for each plant is different, as represented by the different slope of the curves. The diagram is drawn to show that every point results in the fifteen thousand-ton reduction.

Assume that the environmental regulator decides, on equity grounds, to require each plant to reduce emissions by one half, and emit no more than seven and one-half tons. The result would be that plant 1 would incur a total cost represented by area A at a marginal cost of E and plant 2 would incur a total cost of reduction represented by the total of C + B + D and a marginal cost of G.

Alternatively, the environmental regulator could institute a trading system with a total of 15,000 allowances, which allows the plant to emit one ton of SO_2, and allow the

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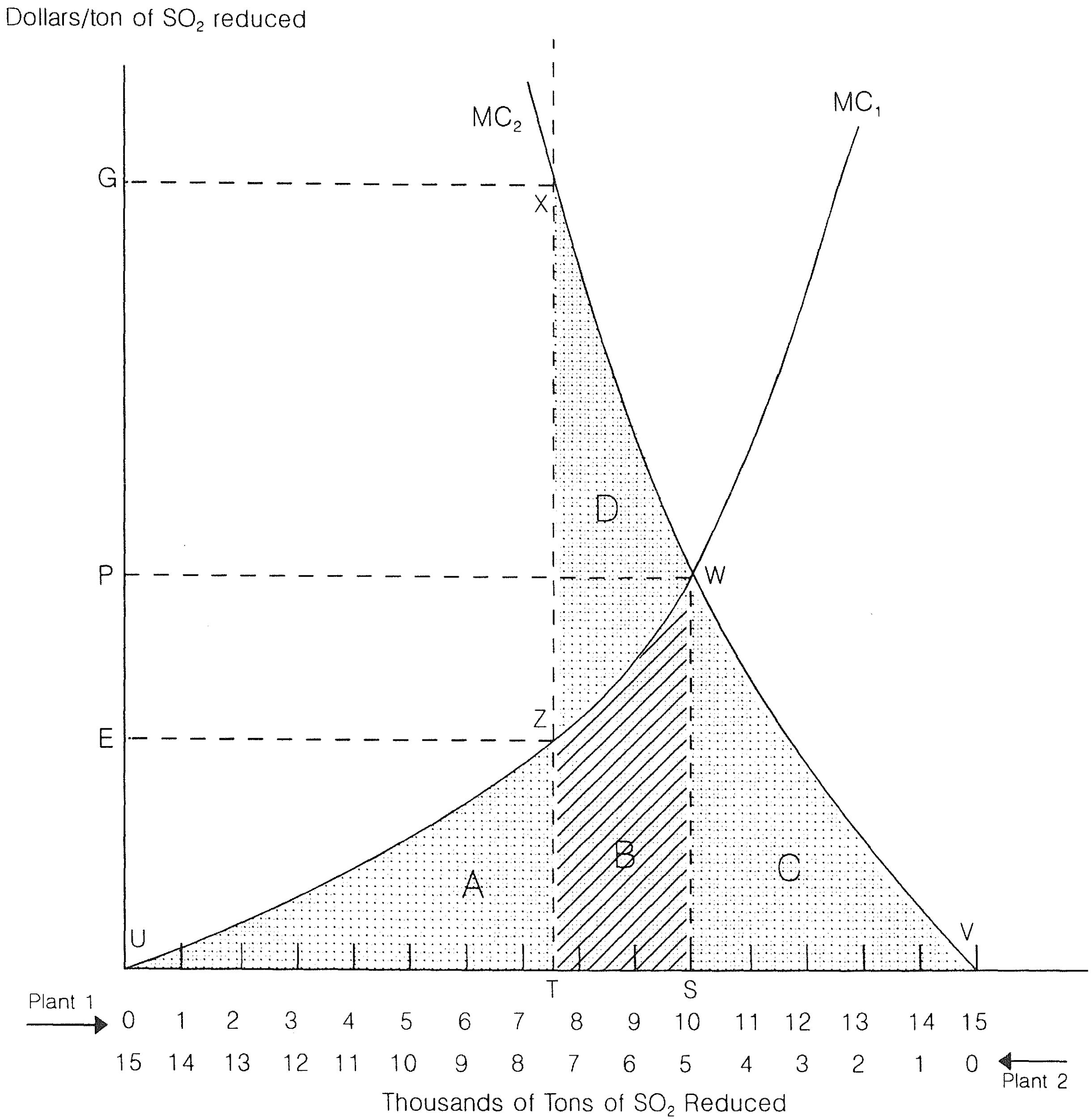
[2] This example is based on T. H. Tietenberg, *Emissions Trading: An Exercise in Reforming Pollution Policy* (Washington, D.C.: Resources for the Future, Inc., 1985).



Total cost of pro rata regulation:	Plant 1 =	Area UZT
	Plant 2 =	Area VXT
	TOTAL	Area UZXV
Total cost with emission trading:	Plant 1 =	Area UWS
	Plant 2 =	Area VWS
	TOTAL	Area UWV

SAVINGS = AREA ZXW

Fig. 3-1. Cost comparison of pro rata versus emission trading environmental control (Adapted from T. H. Tietenberg, *Emission Trading*.)

plant owners to trade allowances. Under this type of system, where plant 1 has a lower reduction cost than plant 2, plant 1's owner would sell allowances as long as the price is greater than the plant's marginal reduction cost. Plant 2 is willing to purchase allowances provided the price is less than the plant's marginal reduction cost. Therefore, trading would occur until the marginal reduction costs were equal. The allowance price then would be P and the net savings from the allowance program, over the proportional reduction program would be represented by the area D. (This simple example ignores the revenue received by the seller and the transactions costs incurred from allowance trading.)

With trading, plant 1 would reduce by 10,000 tons and emit 5,000 tons, while plant 2 would reduce by 5,000 tons and emit 10,000 tons. These quantities, at the point where $MC_1 = MC_2$, are the lowest cost solution; no other combination can achieve the 15,000-ton emission limit at a lower cost. Note that each plant operator knows both the marginal reduction cost and the allowance price. Note also that the marginal cost curves for each plant can be interpreted as allowance supply curves.

A more realistic marginal-cost structure (although the numbers are hypothetical) is presented in Figure 3-2. In this example, two utilities, firm A and firm B, have affected units requiring a 300-ton and 50-ton SO_2 emission reduction, respectively. In this example, other firms exist (unlike Figure 3-1 with only two firms) and all affected firms together (as noted in Chapter 2, there will be over 2,700 units affected by phase II) determine the market price in a more complex but similar manner as shown in Figure 3-1 (again ignoring other complicating factors). Also assume that these two firms are price takers, that is, their actions alone are insufficient to affect the market price.

Various control options are available to the firms which are characterized as being "lumpy." The pollution control devices 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. The next fifty $300 a ton, and so on. The main point is that pollution control is incrementally more expensive. How

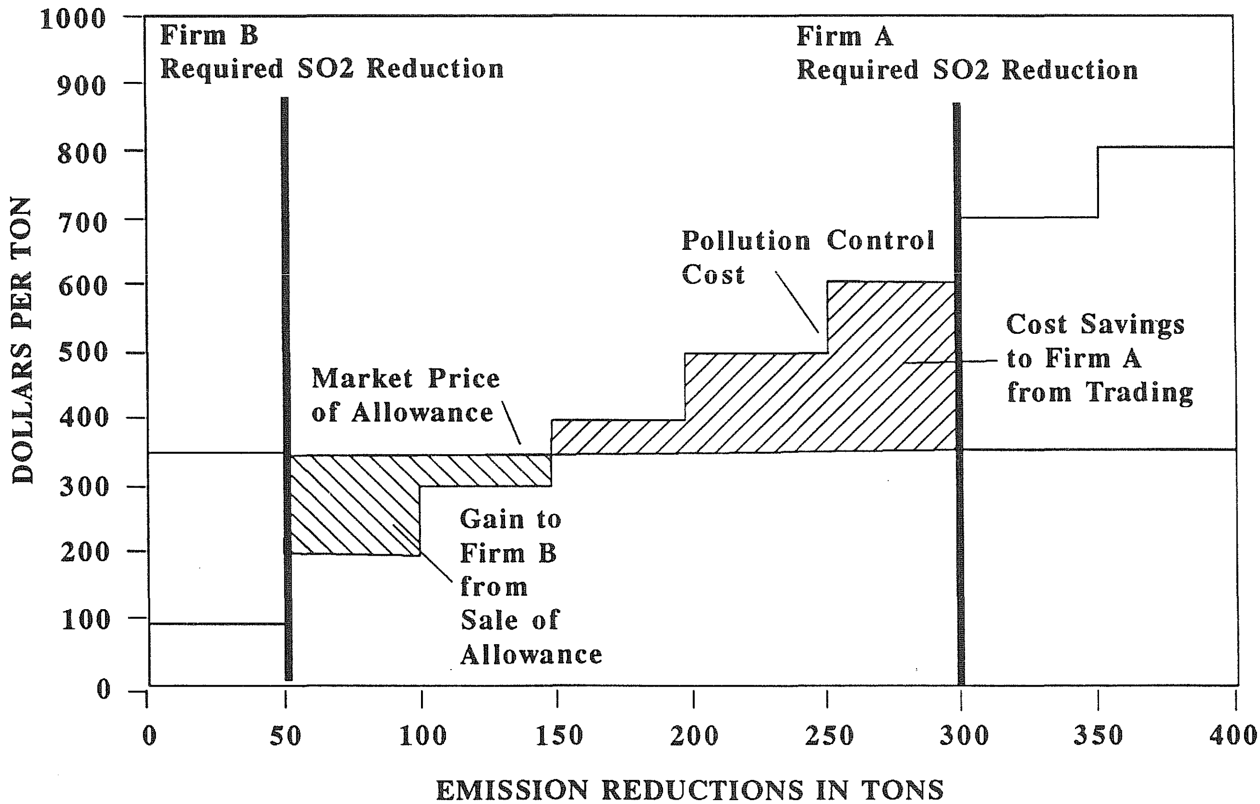


Fig. 3-2. Compliance strategy for two hypothetical firms.

can the utility minimize the cost of pollution control and still meet the required reduction in emissions? The answer, as we have seen, is through allowance trading.

In this example, firm A characterizes a buyer of allowances. 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 3-2 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 parsimony) 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, would change firm A from a buyer to a seller of allowances.

Returning to the example in Figure 3-1, it can be shown that the initial distribution of allowances to the two firms does not affect the final distribution of emissions. This fact is a result of the "sunk-costs-don't-matter" argument. That is, firms have an incentive to trade no matter what the original position of the individual firm. Of course, how the 15,000 allowances are passed out at the beginning matters a lot to the profitability of the two plants (assuming the firms are allowed to retain a portion of the gain or incur some of the loss), and this is precisely the basis for efforts by interested parties to change the allowance allocation scheme in the CAAA in their favor. However, the initial allocation of allowances has no efficiency consequences---only equity ones.

To see this, consider what would happen if both plants (again, from Figure 3-1) were given half the allowances. Since plant 1 can "free-up" some its allowances for less than the allowance price or plant 2's marginal cost, trading would be mutually beneficial. As an extreme example, assume that because of considerable political clout, plant 2 receives the entire allocation forcing plant 1 either to make the entire 15,000 ton reduction or purchase allowances from plant 2. Trading still would be mutually beneficial because of the substantial cost savings plant 1 could achieve and the revenue gain by plant 2's sale of allowances.

The environmental regulator does not need to know the cost information of the firms for this system to achieve the least-cost solution. The implicit assumption is that the environmental regulator does not know and cannot get the information without incurring a large cost. If the regulator did know enough to calculate the outcome under the allowance plan, one might ask what are the advantages. Why not simply tell the regulator to calculate the optimal level of emissions for each plant, and announce what their share of the required abatement will be?

The point is that in a more complex example the computational burden facing the regulator would be immense, even in the unlikely event the regulator was privy to the required cost information for all emitting sources (and could predict future costs as well). In the real world, of course, no government agency has this cost information. Neither do plants know everything about each other. The primary informational advantage inherent in a market for allowances is that each plant needs to know only its own cost structure and the allowance price. The government agency is not required to know very much about the cost structure of any of them. This is also the result of more general mathematical model: For any group of plants and for any existing distribution of emissions across those plants, no alternative regulatory scheme can achieve a given environmental goal for a lower cost than an emission allowance trading scheme.

This is the argument made by economists and others who advocate implementation of market-based environmental regulatory schemes, and who helped to get the CAAA passed. Estimates of the savings that will result from the CAAA allowance market range up to $3 billion per year.[3] Most seem to agree that it will be expensive[4] to bring the electric utility industry into compliance with the CAAA. (There is much less agreement on the question of whether the expenditures are worth it.) If the estimates of the cost savings due to an effective, working allowance market are remotely accurate, then it would appear that all parties involved--ratepayers and utility shareholders--potentially would benefit if the market works.[5]

Whether or not the higher savings figures ascribed to the allowance trading scheme can be realized given the regulatory foundations that now undergird the utility industries is an important open question. In short, economists depend upon the results of their theoretical models when advocating market-based environmental control. The example just given is emblematic of the kind of argument that people make. That example, and nearly all of the more complicated versions that appear in the literature, leave out the effects of utility regulation by public utility commissions on utilities'

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[3] Paul R. Portney, "Policy Watch: Economics and the Clean Air Act," *Journal of Economic Perspectives* 4 no. 4 (1990): 173-81. See also, *Electrical World* (December 1990): 10, which estimated that the cost of complying with the overall emissions cap of the CAAA will be 15 to 30 percent lower than it would be without the allowance trading provisions.

[4] After passage of the CAAA, the Bush administration put the cost of CAAA compliance at $10 billion per year by 1995 and between $22 billion and $25 billion per year by 2005. The cost to electric utilities of the Title IV provisions was estimated by the industry to be between $5 billion to $7 billion per year. ("The Impact of the New Acid Rain Laws," *Electrical World*. Another estimate of compliance with Title IV put the cost at $4 billion per year *with* trading. Without trading the estimate was $2 to $3 billion *more* annually (Portney, "Policy Watch").

[5] Even within a state, it appears there can be no disadvantage to having the allowance market work. At worst, barring market power abuses, the CAAA is simply a command and control system for bringing emissions down to 8.95 million tons annually; action that reduces the effectiveness of the allowance market in a state or group of states can only add to compliance costs.

environmental compliance decisions. Of course, most firms that would be affected by an allowance trading scheme are also, as public utilities, subject to rate-of-return (ROR) regulation in their output markets. Although many observers have noted its importance, there appears to be no formal work investigating the interaction between environmental regulation (whether market-based or not) and the theory of public utility regulation.[6] Section 403 of the CAAA includes language noting the important link between environmental and utility regulation, and ensuring that the role of state commissions will not be altered by provisions of the CAAA.[7]

Summary of the Economic Literature on Tradable Pollution Rights

The extensive literatures on environmental control and on utility regulation are not very well integrated. A subsequent chapter (Chapter 7) attempts to integrate the two using a model of a regulated utility firm facing environmental restrictions to investigate how these two forms of regulation affect one another and the behavior of the firm. This

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[6] See D. N. Jones and R. A. Tybout, "Environmental Regulation and Electric Utility Regulation: Compatibility and Conflict," *Environmental Affairs Law Review*, Boston College, 14 no. 1 (1986), for an examination of the interface between command-and-control environmental regulation and utility rate regulation; D. T. Stathos and M. S. Treitman, "Using Private Market Incentives for Air Cleanup," *Public Utilities Fortnightly* (July 30, 1989), in which the authors suggest that a utility, before deciding whether to trade allowances, should consider how the purchase or disposition of allowances will be treated by the regulator. David Jones of Temple, Barker, and Sloane Inc., quoted in the December 1990 *Electrical World*, names the role of state regulators in allowance trading as "one of the key issues to be resolved." In particular, he notes, "how will the cost of buying allowances be treated by regulators in setting rates?" Douglas Bohi and Dallas Burtraw also point out that the treatment of allowances by state regulators will have a good deal to do with how the allowance market functions, in "Utility Investment Behavior and the Emission Trading Market," Discussion Paper ENR91-04, Resources for the Future, January 1991, Washington, D.C. Forthcoming in *Resources and Energy, 1992.*

[7] "Nothing in this section shall be construed as requiring a change of any kind in any State law regarding such State regulation or as limiting State regulation (including any prudency review) under such a State law," (§403(f)). This language did not appear in the original version of S1630.

section summarizes the relevant market-based pollution regulation literature. As such it is a review of what economists have had to say about markets for emission allowances, and spells out how well the CAAA agrees with some recent recommendations on the design of such markets.

A well-functioning market for any good or service works because it accomplishes the task of providing people with information and with the incentives needed to make efficient use of that information. There is no centralized coordination needed--in fact, such coordination will usually be detrimental. Most markets function in this fashion, but very often there are complications that appear to require intervention by a central authority. In much of economics, ideas have been developed by first asking how things would work if markets were organized perfectly, and then by asking how various imperfections affect those outcomes.

The idea of trading licenses to pollute has progressed in this way. It is interesting for our purposes to follow it, noting those difficulties that appear to be troublesome and the manner in which the CAAA addresses them. We can begin with the earliest writing on the value of allowing a market arrangement to limit pollution. Pigou, in his 1932 textbook *Economics of Welfare*, presents the basics of a scheme of this sort. Later, effluent fees were accepted as the preferred method for controlling pollution through market means. Only in 1968, when Dales published his *Pollution, Property and Taxes* did the notion of trade in licenses to pollute, as we now think of the concept, enter the literature. Dales proposed that by issuing tradable licenses and constraining the overall level of emissions, pollution could be reduced more cheaply than by a command-and-control (CAC) approach.

In 1972, Montgomery[8] proved that under a certain set of conditions, Dales' insight was mathematically correct. That is, no CAC scheme can achieve a given level of air quality at a lower cost. Montgomery considered two alternative permit trading systems. One, an ambient permit system (APS), defined allowable emissions in terms of

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[8] W. David Montgomery, "Markets in Licenses and Efficient Pollution Control Programs," *Journal of Economic Theory* (1972): 395-418.

pollutant levels at a set of monitoring points in a given geographical region. The other, an emission permit system (EPS), allocated to sources of pollution the right to emit pollutants up to a certain rate. His results showed that an APS has desirable efficiency properties, though it demands much of the emitters in that they must acquire information about and make trading decisions in several permit markets. The EPS in its pure form is much less expensive for firms (though much more demanding of the regulator), but it satisfies Montgomery's efficiency criteria only in restrictive cases. The allowance trading system of the 1990 CAAA corresponds to Montgomery's emission permit system (this system is outlined in more detail in Appendix B).

The example of the previous section captures the essence of the arguments in favor of allowance trading. If the assumptions are met (allowance price information equally available to all parties, control cost information available, trading between parties not restricted, and so on), then costs are minimized by allowing those firms for whom abating is relatively inexpensive to cut back their emissions and sell allowances to others who find it relatively more expensive to reduce pollution levels. As was noted earlier, total industry costs and profits do not depend on the initial allocation, because what one firm pays in allowance fees the other receives; the expenditures and receipts on allowances is a wash to the industry.[9] Once again, though, the equity effects of this allocation decision are enormous. That is, for purposes of overall costs and emissions, it matters not at all whether all of the allowances are given to a single firm, or if each receives some portion of the 8.95 million available. Theoretically, the same distribution of emissions will result in any case. Obviously, the manner in which the two firms (and their ratepayers) are affected individually is quite sensitive to the initial allocation and transactions cost.

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[9] It is very important to keep this point in mind, for it holds exactly in the allowance trading program of the 1990 CAAA. There, the initial allocation of allowances is extremely important and inspired some of the most spirited political debate. However, if the allowance market is really competitive in nature, then the overall outcome of the system does not depend in the least on how they are divided up (assuming negligible transaction costs).

Numerous studies have extended Montgomery's results. Some of these are very much in the spirit of Montgomery, though they refine his model in one way or another. Atkinson and Tietenberg, for example, explore the empirical properties of the two systems. Krupnick, Oates, and Van De Verg note that, with certain modifications, the EPS may attain efficiency more readily (that is, with lower costs of pollution abatement) than would Montgomery's version.[10] Their pollution offset system (POS) is similar to the scheme specified in the EPA's 1986 Final Trading Policy.[11] McGartland and Oates refined the Krupnick, Oates, and Van De Verg version of pollution offsets and showed that one of Montgomery's key results--that an equilibrium after emissions trading will satisfy a critical condition on emission distribution across firms--does not always hold.

Others have attempted to discover whether the fundamental arguments in favor of allowance trading still hold when one or more of the usual assumptions are relaxed. Recall that Montgomery's model, though very elegant, does assume that perfect competition prevails in the permit markets and in the output markets of the polluting firms. In many cases, neither of these assumption should be expected to hold. Here we

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[10] See Alan J. Krupnick, Wallace E. Oates, and Eric Van De Verg, "On Marketable Air-Pollution Permits: The Case For a System of Pollution Offsets," *Journal of Environmental Economics and Management* (1983). The key difference is that Krupnick, Oates, and Van De Verg allow trades to occur that reduce air quality at sites which previously fell below the ambient air quality standard. Scott Atkinson found that the cost savings which accrue to trading schemes are due largely to this redistribution of pollutants from high- to low-level areas in "Nonoptimal Solutions Using Transferable Discharge Permits: The Implications of Acid Rain Deposition," in E. Joeres and M. David, eds., *Buying a Better Environment: Cost Effective Regulation Through Permit Trading* (Madison, WI: University of Wisconsin Press, 1983). See also Albert M. McGartland and Wallace E. Oates, "Marketable Permits for the Prevention of Environmental Deterioration," *Journal of Environmental Economics and Management* (1985): 210; and Tietenberg, 1985 for a discussion and clarification of this point.

[11] See the EPA's *Emission Trading Policy Statement, General Principles for Creation, Banking, and Use of Emission Reduction Credits*, Final Policy, 51 Federal Register, 43,814 (1986).

find that complications taking the model away from the perfect, sanitary world envisioned by Montgomery could affect his results.

In 1984, Hahn looked at how the existence of one firm which holds market power in the permit market affects outcomes. He found that only if the regulatory agency (that is, the EPA) distributes permits in a cost-minimizing fashion will the market equilibrium be efficient (an outcome which could then be achieved with a CAC program anyway). That is, an allowance market might only be helpful if the government does its job perfectly. McGartland showed that if only a few traders enter the market for permits, even the POS may be inefficient. The possibility exists for free-riding by emitting firms who benefit without cost from trades between other firms. Another twist was considered by Malueg, who looked at what happens if the permit market is competitive but the emitting firms are oligopolistic in a single output market. He found that an equilibrium in a permit system may actually reduce social welfare compared to a corresponding and environmentally equivalent command-and-control system.

Others have examined the effect of different schemes for allocating allowances. If the distribution of allowances is achieved through an auction mechanism, for example, then care must be taken to ensure that asymmetries in the affected industry are not worsened due to the allowance program. If there is one firm with monopoly power in the output market affecting prices for a host of smaller price taking firms, then Oehmke has found that the result may not minimize abatement costs, though the inefficiency due to this market power was found to be small in his model.

In summary, then, though many observers seem to agree that there is much to be gained through the implementation of a market-oriented air quality regulation, there are also qualifications to that support. Empirical evidence indicates that the trading schemes employed to date have been very effective in reducing the cost of achieving national air quality standards. Hahn and Hester estimate that cost savings due to emissions trading activity has amounted to billions of dollars (beginning in 1974 when EPA first began to use trading policies up to 1989).[12]

How, then, should an allowance trading market be designed? The evidence is fairly strong that there are a variety of things that can go wrong, reducing the effectiveness of market-based emission reduction schemes. One might ask whether the Clean Air Act Amendments, which establishes such a scheme on a grand scale for sulfur dioxide emissions in the U.S., has been designed so that it can work. A few authors have also laid out various sets of guidelines for the design of emission allowance programs.[13] The more recent of these pieces are helpful in evaluating whether the CAAA are likely to perform in the manner that they are intended. Five recommendations seem fairly critical.

First, does the allowance market itself resemble the theoretical version that economists have been talking about all this time? Evidently it does, though there is clearly a good deal of room for the EPA to interpret certain of the trading provisions as it sees fit. It seems reasonable to suppose that the EPA will choose to interpret the 1990 bill in a manner consistent with its 1986 Final Trading Policy.[14] This system of

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[12] Hahn and Hester, *Yale Journal on Regulation* (1989). Also see James S. Diemer and J. Wayland Eheart, "Transferable Discharge Permits for Control of SO_2 Emissions From Illinois Power Plants," *Journal of the Air and Waste Management Association* (1988): 997-1005, for estimates of the cost savings that would result from various trading arrangements. They find that savings of up to 60 percent over a uniform decrease program may be possible. For an older estimate, see also Michael T. Maloney and Bruce Yandle, "Estimation of the Cost of Air Pollution Control Regulation," *Journal of Environmental Economics and Management* (1984): 244-63.

[13] See, for example, Roger G. Noll, "Implementing Marketable Emissions Permits," *American Economic Review* (1982): 120-24; Robert W. Hahn, "Designing Markets in Transferable Property Rights: A Practitioner's Guide," in E. Joeres and M. David, eds., *Buying a Better Environment*; Robert W. Hahn and Gordon L. Hester, "Where Did All the Markets Go: An Analysis of EPA's Emissions Trading Program," *Yale Journal on Regulation* (1989): 109-53; and James T. B. Tripp and Daniel J. Dudek, "Institutional Guidelines for Designing Successful Transferable Rights," *Yale Journal on Regulation* (1989): 369-91.

[14] See the EPA's Final *Emission Trading Policy Statement*, 43,814.

allowance trading would most closely resemble a modified version of the pollution offset system of Krupnick, Oates, and Van De Verg, who claim that such a system performs quite well.[15]

Second, will the CAAA allowance trading provisions be successful in minimizing or avoiding the deleterious effects of monopoly power in the allowance market? One important concern is that large holders of emission allowances will choose to withhold their excess allowances rather than offer them for sale to potential entrants into the electric generating industry. It is far from clear under what conditions such a strategy would be advantageous. Misiolek and Elder argue that a large firm can increase its long-run profits (ignoring the economic regulator) by holding onto its allowances, shutting potential entrants out of its product market and perhaps causing some existing firms to fail. This may be true even though the perpetrator's abatement and allowance costs increase. A great deal of interest in whether the allowance market will operate in a competitive manner was demonstrated during the debate on the CAAA. As noted in Chapter 2, however, while there is some concentration in phase I, no single utility or holding company will control a significant portion of the original allocation to control the market price.

Third, the mechanism by which allowances are allocated, depending largely upon past utilization of generation capacity and an auxiliary auction arrangement to guarantee that IPPs and others will be able to acquire allowances, does appear to meet with the recommendations of previous writers. Also, the use of 1985 to 1987 operating dates to determine the allocation of allowances is imperfect, as it discriminates against plants that reduced their emission rates just before 1985 and favors those that took steps to reduce emissions in 1988 or later. However, the CAAA does allow owners or operators to petition EPA for different base years.

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[15] Note, however, that McGartland and Oates, "Marketable Permits for the Prevention of Environmental Deterioration," refined the Krupnick, Oates, and Van De Verg version of pollution offsets and showed that one of the key results in favor of emissions trading having to do with the distribution of emissions across firms does not always hold.

Fourth, Tripp and Dudek note the importance of the institutional makeup of the governing agency for trading systems to work. The agency, they say, must have "clear legal authority" to generate allowances, it must have the "technical capability" to design and implement the program, and the resulting program must be "evasion proof." The CAAA appears to give EPA this authority and it has been developing the technical capability since passage of the Act. By evasion proof, Tripp and Dudek simply mean that affected plants cannot employ other legal strategies (possibly administered by government agencies other than the one in charge of emission control) in order to circumvent the program altogether. It would seem that the CAAA does indeed satisfy this requirement as well.

Fifth, does so much uncertainty surround this bill that utilities will simply choose not to take part in the allowance trading program at all? Hahn and Hester regard uncertainty concerning property rights accompanying emission allowances as one of the most important impediments to effective working of past EPA-administered trading systems (as, for example, the bubble, offset, and banking programs). This would seem to run counter to § 403(f) of the CAAA, entitled "Nature of Allowances," which states, as noted earlier, that the issuance of an emission allowance "does not constitute a property right." Will affected units wish to enter a market where they are told expressly that they do not have a property right to the commodity being traded? The issue of property rights was discussed in Chapter 1.

One final, striking note about the allowance trading research that economists, with few exceptions, have carried out little work on how things are affected if the output market (electricity market) is regulated.[16] Title IV of the CAAA will affect electric

[16] For exceptions see R. Hahn and R. Noll, "Barriers to Implementing Tradable Air Pollution Permits: Problems of Regulatory Interactions," *Yale Journal on Regulation* 1 (1983): 63-92; David A. Malueg, "Welfare Consequences of Emission Credit Trading Programs," *Journal of Environmental Economics and Management* (1990): 66-77. In this article the concern is with the effect upon trading behavior of some monopoly power in the output market. He does not consider the additional complication of regulation in the output market. Also, see Robert W. Hahn, "Government Markets and the Theory of the nth Best," CSIA Discussion Paper 91-14 (Cambridge, MA: Harvard University, Kennedy School of Government, December 1991) and footnote 6 above.

utilities almost exclusively. They face incentives of a sort that most industries do not, in that their profits and prices are monitored and regulated by states and FERC. This fact is of concern to, and has been noted by, many observers and industry leaders.[17] As was mentioned earlier, the CAAA contain language designed to ensure that the decisions of state public service commissions will not be interfered with as a result of the new bill. However, the vast work on the economics of utility regulation does not appear to have been consulted in connection with allowance trading. One would think that this literature should be able to give us some guidance in predicting how the bill will work. It seems to be at least as important as any consideration such as market power, and so on. Chapter 7 will provide an overview of the literature on public utility regulation to set the stage for an economic model that integrates the economic and environmental constraints and begins the development of a regulatory framework for commissions and FERC to consider.

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[17] See, for example, Marie Leone's "Cleaning the Air the Market-Based Way," *Power* (December 1990), 10.

PART II

COMPLIANCE PLANNING ISSUES

CHAPTER 4

THE ROLE OF FEDERAL AND STATE REGULATORS IN ADMINISTERING TITLE IV OF THE CLEAN AIR ACT

Four significant actors are involved in the implementation of the CAAA. First, there is the federal EPA with authority to administer most of the Act's provisions including allocating allowances and tracking them. Second are the state air quality or environmental protection agencies, which will play a significant role in the permitting process of phase II. Third are the affected utilities which, acting through their "designated representatives," have specific reporting requirements as well as emission limits. Fourth are the economic regulators, the state public utility commissions, and FERC. While they have some direct responsibilities outlined in the CAAA, they also play a significant role as economic regulators in the utility planning process that is not specified by the CAAA.

This section addresses the role of these actors in CAAA implementation by outlining the main regulatory reporting relationships they have as described in EPA's proposed rules. These relationships are diagrammed in Figure 4-1. In general, the federal EPA is the most directly involved regulatory agency, although important ancillary roles exist for state commissions. What's more, the state air quality board or state EPA plays a more direct role in CAAA administration in phase II.

The Designated Representative and Filing Responsibilities

While the owner or operator of an affected unit has the responsibility to ensure its compliance with the requirements of the CAAA, the federal EPA is the main administrator. Each owner and operator of an affected source and unit will interact with the EPA exclusively through a "designated representative." The designated representative would not be personally liable (in the absence of any criminal wrongdoing) should difficulties arise, and could be, but does not have to be, the plant

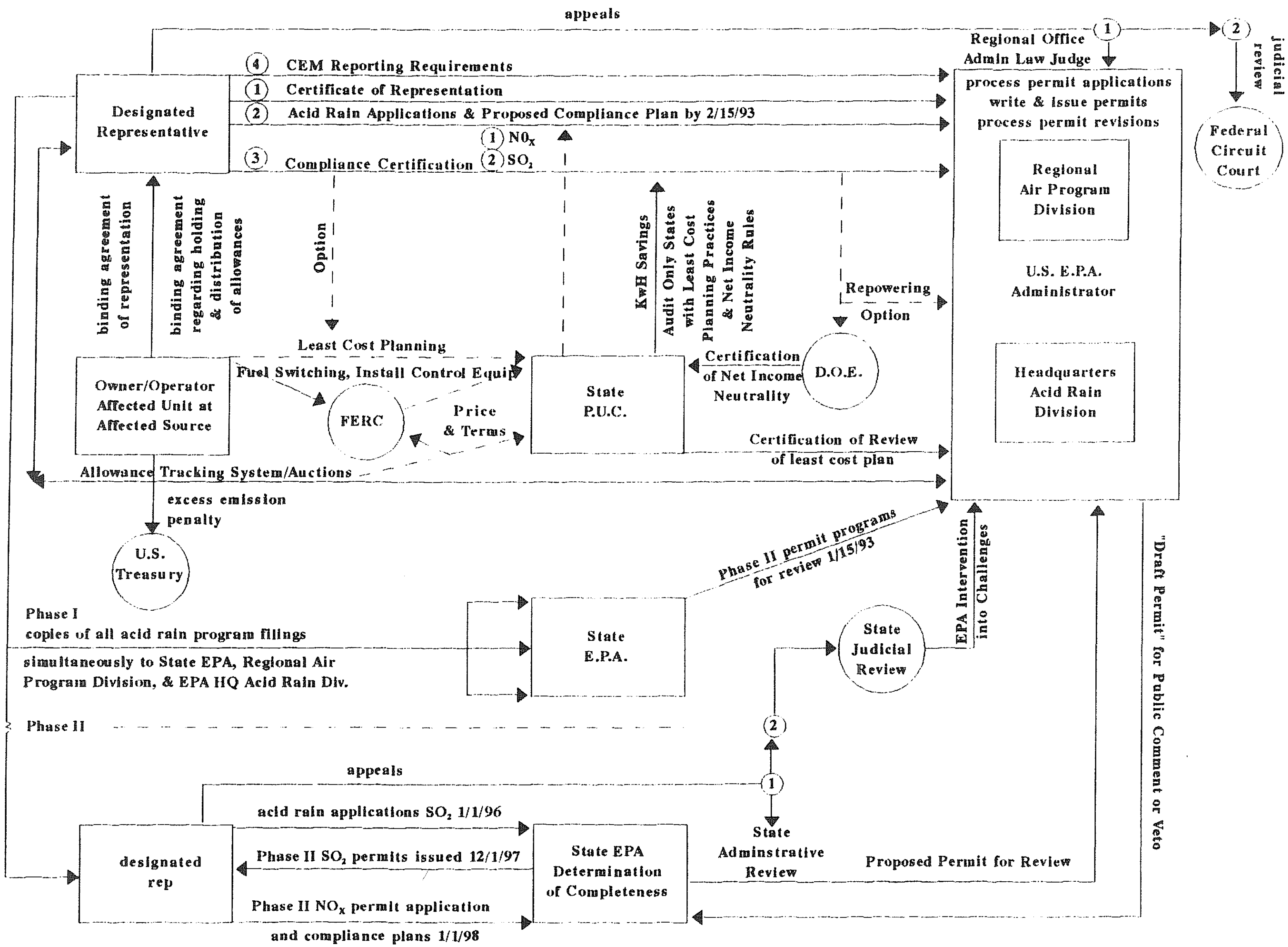

Fig. 4-1. Flow chart of regulatory reporting relationships (Source; Authors' construct).

manager. As a prerequisite to obtaining a permit, the designated representative must file a Certificate of Representation with the EPA which includes a binding agreement of representation and a binding agreement regarding the holding and distribution of allowances. The permit is an authorization from EPA under Title V of the CAAA and is distinct from Title IV allowances. The Certificate states, among other things, that the designated representative was selected by an agreement binding on all owners and operators. The Certificate also must identify an alternative designated representative to act when the designated representative is unavailable. The designated representative would represent the owners and operators of each affected unit in matters pertaining to the acid rain program, including submitting and complying with acid rain permits, permit applications and compliance plans, and holding, transferring, and disposing of allowances.

During phase I and phase II of the CAAA, copies of all acid rain filings are sent simultaneously to the state environmental protection agency, the Regional Air Program Division of the EPA, and the EPA Acid Rain Program headquarters. The current proposal does not specify whether the Regions or Headquarters will issue permits, but instead uses the term "Administrator." Although EPA's current thinking is that the Agency would employ a team approach where EPA Headquarters, Regional Office, and State would work together, the regulatory stance of the EPA historically suggests the Regional Air Program Division as the most likely candidate for Administrator. The designated representative is to file the *Acid Rain Permit Application and Proposed Compliance Plan* with the EPA Administrator by February 15, 1993. This representative must also submit, prior to or along with the source's permit application, a proposed monitoring plan. Phase I emission-monitoring-system verification test results would not be required by this deadline. The CAAA allows flexibility to utilities when choosing from a variety of options for their affected units to achieve the most cost-effective means of complying with the mandated SO_2 and NO_x emissions reductions. The state commissions and FERC, in their review of the long-range planning of utilities, may influence a utility's plan as they attempt to comply with the acid rain program requirements. To date, approval or acknowledgment of the compliance process or the compliance plan itself appears to be an important role for the state commission in the administration of the CAAA. This involvement by the commission, however, is not mandated by the CAAA.

Conservation and Renewable Energy

The CAAA does not require the designation of a compensating unit when reduced utilization occurs at a phase I unit as a result of a program of energy conservation or improved efficiency measures. However, to get credit for such measures, these programs should be described in the unit's proposed compliance plan and the kilowatthour savings resulting from these measures must be verified by an independent auditor, by the state commission, or by the entity with utility-rate regulatory authority. Only states that have adopted least-cost planning and net-income neutrality rules for investments in energy conservation would be qualified under the CAAA to verify demand-side measures. DOE must certify that the state regulatory authority has implemented provisions that guarantee net income neutrality. In the case of qualified renewable energy generation, the state commission must certify that the applicant has, and is, implementing a least-cost plan. Finally, all applications for allowances from the conservation and renewable energy reserve (described in Chapter 1) must be certified as to the truth and correctness of the information submitted to EPA. The CAAA requires that utilities submit their applications to their state commission for review of accuracy and compliance with the requirements of the Act and the proposed regulations. EPA requires in the application a signed certification by a state regulatory authority that this review was completed. For repowering of a unit, the designated representative must obtain DOE and EPA approval of the repower technology during the repowering application process (this too may be considered eventually by the state commission, but again is not mandated by the CAAA).

Permitting Process

During phase I the EPA will process permit applications, write and issue permits, and process permit revisions. (Again, a permit is an authorization to emit SO_2 granted by EPA as stipulated by Title V, and should not be confused with Title IV allowances.) In cooperation with state and local air quality agencies, the EPA will monitor compliance and, when necessary, take appropriate enforcement action. As mentioned, the designated representative is required to submit the acid rain permit application and proposed compliance plan. The permit application contains both a certification for each affected unit indicating it will meet the applicable emissions limitation requirements in a timely manner and a certification indicating it will hold enough allowances to cover emissions for the year. EPA will review these applications, and if approved, issue the permits by August 15, 1993. The permits have a term of five years (the first term being 1995-1999) and will take effect on January 1, 1995.

As noted in Chapter 1, phase I units may apply for a two-year extension of this compliance deadline provided that they install 90 percent sulfur dioxide removal technology or transfer their emissions to a unit or units that have such technology. In this case, the designated representative would also submit a Compliance Certification annually, quarterly, or as otherwise mandated. The Compliance Certification is a departure from traditional methods of determining compliance (that is, on-site inspections and source-specific investigatory letters).

The appeal procedures include an administrative appeal and judicial review. Disputes involving phase I acid rain permits will be handled first through an EPA Regional Office administrative law judge. If not resolved at this level, the Federal Circuit court will offer the next level of recourse for the owners and operators of an affected unit.

During phase II, which begins January 1, 2000, the state Environmental Protection Agency will be the permitting authority unless it is not adequately administering or enforcing the program, in which case the federal EPA will be the permitting authority. The Regional Air Program Division would be responsible for reviewing state permit programs beginning in 1993 for consistency with the acid rain program and for reviewing proposed state-issued operating permits. The state agency will make a "determination of completeness" and forward the "proposed permit" to the EPA for review. Standardized forms for permit applications, compliance plans, permits, and compliance certifications will ensure national consistency and a smooth transition from phase I to phase II. EPA will write a "draft permit," give public notice, and allow for public comment. Following submission of all comments, the proposed permit will then be revised. Assuming the EPA does not veto the permit application, the acid rain permit would then be issued. The state permitting authority is required to issue Title V permits containing phase II SO_2 requirements to all affected sources by December 31, 1997. The state permitting authority must also begin to process NO_x permit applications in 1998. Within four years after the state permitting authority receives EPA approval of its Title V permits, it must complete the process of issuing permits for all CAAA requirements to all affected sources in its jurisdiction.

Appeals of the state-issued permits are carried out through state administrative and judicial appeal procedures. The EPA reserves the right to intervene in any challenges to acid rain conditions brought in the state courts and proposes that it be given notice of any such challenges. Further appeals can be made through administrative review at the EPA and judicial review in the Federal Circuit Court.

Allowance Tracking System

The federal EPA will establish an Allowance Tracking System no later than January 30, 1993. EPA will determine a unit's compliance by deducting from the unit's subaccount allowances equal to the SO_2 emission tonnage reported for the unit each year. As mentioned, the "allowance transfer deadline" is proposed as January 30 of the calendar year following the year for which compliance is being established.

The allowance market participants themselves will make the market work and the EPA has eschewed any option that would expand its role beyond those expressly prescribed by the CAAA. As mentioned, the Chicago Board of Trade has announced its intention to create an allowance exchange. The market activities of the affected units (that is, cash price paid for allowances and other terms of the contracts, such as coal deliveries or power purchase arrangements) may come under the scrutiny of the state commission's economic regulation. Price information will be available from EPA auction results, while price and contract terms may be reported to FERC and state commissions.

Continuous Emissions Monitoring Systems

Owners and operators of an affected unit or units are required to install a continuous emissions monitoring system (CEMS). The proposed rules include requirements for (1) a monitoring plan for compliance plan and permit, (2) written notification of monitoring performance tests thirty days prior to conducting the tests, (3) maintenance of records of emissions and flow, (4) reports of performance certification tests, (5) reports of quality assurance and quality control tests, and (6) quarterly submissions of monitoring data.

Penalty for Excess Emission

As noted in Chapter 1, there is a statutory-based penalty of $2,000 a ton for excess emissions (that is, emissions beyond allowances held). In addition, the source must cover this excess with allowances in the following year (to maintain the tonnage cap). This is intended to eliminate any financial benefit owners and operators of affected units might otherwise derive from exceeding their emissions limitations as required by the CAAA. This penalty is estimated to be more than twice the expected market value of an allowance.

Least-Cost Planning Issues

Three major least-cost planning issues are associated with emissions trading and compliance planning. The first concerns whether state public utility commissions engaged in least-cost or integrated resource planning should incorporate CAAA compliance planning, including the use of emissions allowance trading, into their least-cost planning process. If the answer is yes, the second issue is how emissions allowance trading and compliance planning ought to be reflected in least-cost planning. The third issue concerns the least-cost planning requirements of CAAA § 404(f), which must be fulfilled for utilities to receive bonus allowances for qualified conservation and renewable energy sources. (See preceding discussions on the conservation and renewable bonus reserve.)

CAAA compliance planning strategies, including emission allowance trading, would likely be a part of least-cost or integrated resource plans in those states that have these programs. Unless compliance plans and strategies are incorporated into the least-cost planning process, the result of least-cost planning would be something other than a least-cost plan. For a state commission to affirm, accept, or approve a least-cost plan, it must be able to assure itself that a utility's planned demand-side and supply side investments result in energy services being provided to the customer at the least cost. If a utility has any fossil fuel burning units that will be an affected SO_2-emitting unit under either phase I or phase II, then the utility's costs will be directly affected by the CAAA. This is true even if the utility's units all emit under 1.2 pounds of SO_2/million Btu, because the utility receives emissions allowances for the unit's baseline emissions times 120 percent. Excess allowances can be banked or sold on the market. Also, the CAAA affects the dispatch priority of all affected units. The utility would need to factor in the opportunity cost of the emissions allowances before expending the allowance through generation that leads to SO_2 emissions. The opportunity cost of a current vintage-year allowance would be no less than its current market price. Even utilities that rely entirely on hydropower, nuclear energy, or both and thus have no affected units would be affected indirectly by the CAAA because they would have to consider its effect in any future capacity planning decisions.

The second issue concerns how compliance planning would be integrated into least-cost or integrated resource planning. Actually, compliance plans make such planning a simpler process. CAAA compliance planning provides a means by which at least one externality (to the extent that the plan deals with externalities), the effect of SO_2 emissions, becomes a partially if not completely internalized cost. The alternative resources in least-cost planning would each have a different compliance cost. Certain alternative resources could also produce offsetting revenues by freeing emission allowances. Capital and operating costs can be offset by revenues from the sale of emission allowances. These costs and potential revenues should be included for each demand- and supply side resource considered in a least-cost plan. For example, retrofitting an existing plant with a scrubber would increase the plant's capital cost and affect its operating cost. If the scrubber resulted in overcontrol, however, the utility would be free to sell, use, or bank the allowances it would have otherwise used to run an unretrofitted plant. Similarly, the use of conservation or demand-side management practices has the potential of freeing allowances and producing revenues that would offset the cost of the option. Once the costs (including emissions compliance costs) of all demand- and supply side resource options are considered, a state commission can review a utility's least-cost plan following its normal procedure.

It may be necessary, as a matter of expediency for phase I, to consider initially what the least-cost compliance planning options are outside of a comprehensive least-cost planning process. However, it makes sense to include CAAA compliance options in future least-cost planning processes, particularly since new supply side options that rely on fossil fuel will require emission allowances and, as noted, true least-cost planning requires a systemwide comprehensive approach.

The third issue concerns bonus allowances for qualifying conservation and renewable resources. To qualify for the available bonus allowances, as noted earlier, a utility must engage in least-cost planning. The least-cost plan must integrate demand-side and supply side resources on a consistent basis and be reviewed and approved or accepted on a regular basis by the state public utility commission or other applicable ratemaking authority. The plan may consider and incorporate the social and environmental costs and benefits of the resource investment. The planning process must provide for public participation, and the utility must implement to the maximum extent practicable any plan or filing as approved or accepted.

An option commissions may consider as part of a least-cost plan is a bidding program to reduce sulfur emissions. In such a program third parties could bid against each other (and perhaps the affected utility) to reduce the SO_2 emissions--either at a particular unit or system wide. Possible participants include scrubber manufacturers, coal and allowance brokers, or other utilities. The bidders would present a package of compliance options that may combine control technology, buying and selling of allowances, and fuel switching, or all of these. If the strategy of the winning bidder involved overcontrol, then the bidder may take title to the freed-up allowances. Such a bidding program could be integrated into the least-cost plan in a similar manner as competitive bidding for generation in some states. Compliance decisions made as a result of commission-approved bidding could also be presumed prudent as an incentive to the utility provided the commission believes there was sufficient competition in the bidding process.

Overview of Compliance Planning

Range of Available Options

Emissions allowance trading needs to be examined in the context of the diverse range of options a utility has to comply with the CAAA. They broadly fall under options that directly reduce emissions, those that reduce emissions by modifying generation requirements, and those that meet compliance standards by making use of emission allowances (Figure 4-2). These options are neither mutually exclusive nor independent, and they may have to be integrated to develop a comprehensive compliance strategy.[1] Compliance plans and strategies, therefore, may be best developed on a systemwide basis.

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[1] For a more comprehensive overview of clean air compliance options and strategies, see Electric Power Research Institute, *Clean Air Response: A Guidebook to Strategies* (Palo Alto, CA: Electric Power Research Institute, 1990), RP 3199-1.

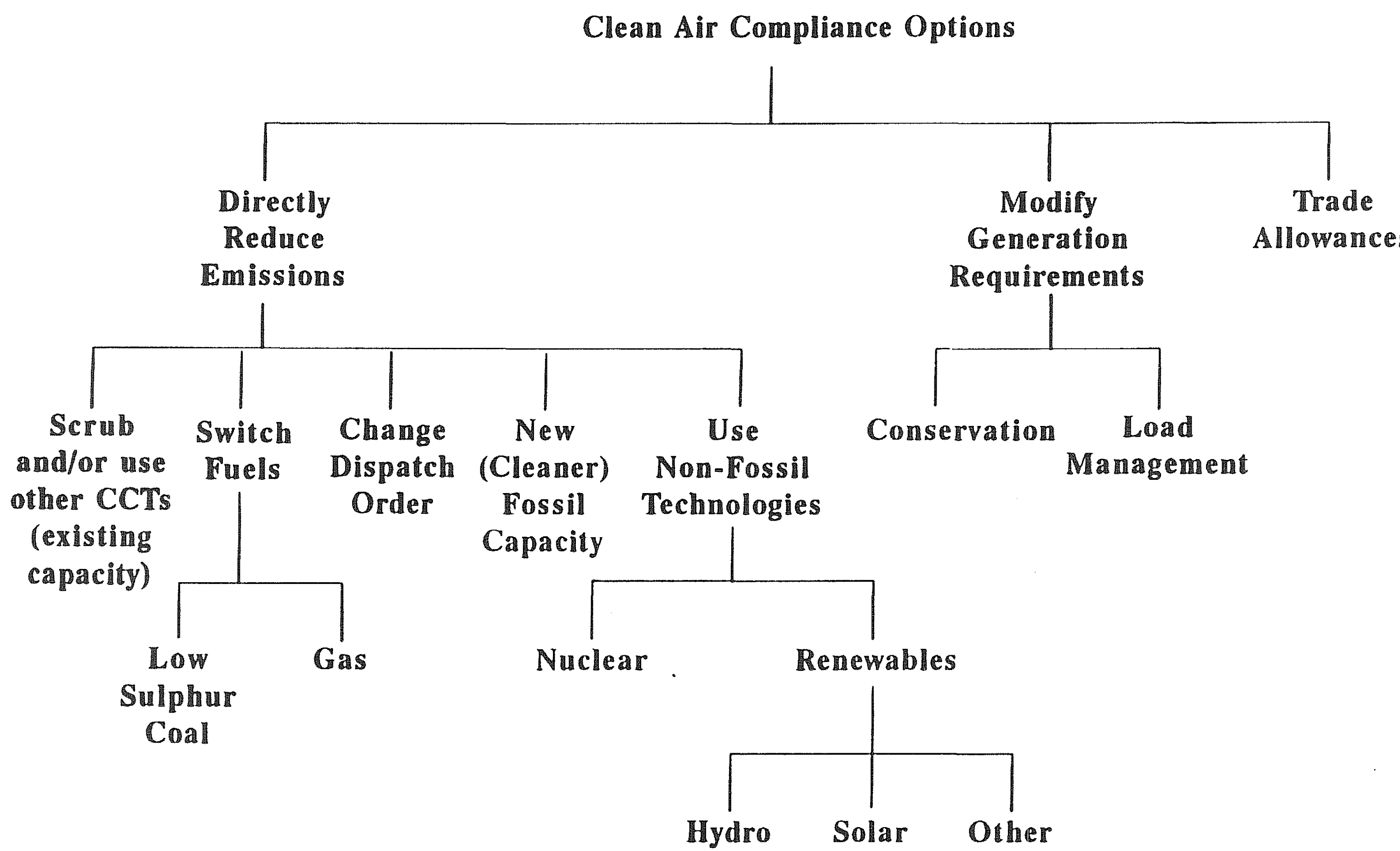

Fig. 4-2. Range of clean air compliance options (Source: Authors' construct).

Compliance options that directly reduce emissions include scrubbing and other clean coal technologies (CCTs), coal conversion, switching to a lower sulfur coal, switching to a natural gas fuel, making greater use of nonfossil power technologies such as nuclear, hydro, solar and other renewables, and redispatching existing fossil-fueled plants to reduce emissions.[2] Compliance options that reduce emissions by modifying generation requirements include conservation, load management, and other demand-side management (DSM) options. Finally, use and management of emission allowances, the focus of this current report, constitute a compliance option. A utility may choose to overcomply on certain of its plants using perhaps a combination of options from the first two categories and the surplus allowances to meet compliance requirements on other plants. It also can purchase allowances from the market to do the same.

Factors that Govern the Choice of Options

A comprehensive compliance strategy that considers a mix of compliance options is more likely to identify lower cost strategies than a more limited approach. A comprehensive approach would require examining the options with an array of interrelated factors that include, among others, technological feasibility and performance history, capital (including retrofit, repowering and replacement) costs and operating expenses, potential revenues from implementing an option (such as revenues from selling the byproducts of a wet scrubbing process), the projected price of emission allowances, state commission policy on the recovery of compliance costs and the sharing of possible allowance profits, and the uncertainty and the risks attending each of the aforementioned factors. In general, a utility is likely to prefer options that have a proven record of technological performance, involve low retrofit costs, have capital and operating costs

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[2] For a detailed discussion of clean coal technologies, see U.S. Department of Energy, *Clean Coal Technology Demonstration Program* (Washington, D.C.: U.S. Department of Energy, 1990).

that are likely to meet with state commission approval, and carry small uncertainties and risks. It is unlikely that any given option will satisfy all or even most of these desirable criteria. An optimal compliance strategy will try to balance the costs, benefits, and risks to maximize the net gain to the utility. To develop such a strategy, it is important to examine the factors that characterize each compliance option.

Technological Feasibility and Performance History

The compliance requirements of each individual utility and plant owned by a utility may vary. Some compliance options will be technologically more effective in controlling pollutant emissions from plants of a certain design and fuel type than others. Also, the various technologies for controlling emissions may vary with regard to their performance history. As examples, wet scrubbing technologies are capable of removing 90 percent or more SO_2 on a wide variety of coals with reagent utilization ratios (which measure the efficiency of the sulphur absorbing chemical) between 1.0 and 1.2, while dry scrubbers are more effective on low sulphur western coals achieving 70 to 90 percent SO_2 removal at reagent ratios of 0.8 to 1.1. Also, wet scrubbers have been used much longer and more extensively than dry scrubbers, accounting for about 92 percent of total scrubbed capacity in the United States.[3] Other things being comparable, a utility is more likely to choose a compliance technology with a proven performance record to minimize the risks of underperformance.

Capital and Operating Costs

Implementing a compliance option may involve retrofit, repowering, and replacement costs depending on the extent of changes needed to equip an existing plant with emission control devices. Switching to a different fossil fuel (such as natural gas), clean fossil alternatives, or nonfossil alternatives (such as nuclear, hydro, and

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[3] Electric Power Research Institute, *Clean Air Response*, Part II, III-6.

renewables) involves new construction costs. In addition to capital costs, each compliance option changes the operating costs of existing plants or introduces new operating costs. Depending on the existing generation mix of a utility and prevailing/expected regulatory treatment of various costs, a utility may favor one type of option or technology over another. For example, if a utility is burdened with an excess capacity problem, it is unlikely to choose options that add new capacity to the system, even if such options appear favorable on the basis of pure cost. Besides direct capital and operating costs, each option may involve indirect costs such as those due to potential reduced availability that also may influence a utility's compliance choices.

Revenues and Earnings

A compliance option may generate additional revenues for a utility. The best example is, of course, potential earnings from sale of allowances. Another example is the revenues from the sale of byproducts such as sulfuric acid from the use of certain "regenerable" scrubber technologies.[4] Regulatory treatment of such earnings will govern whether such options are favored by a utility. For example, if a utility is allowed to retain a significant part of earnings resulting from implementing an option, the option is more likely to be favored over another that generates no additional earnings. On the other hand, if the utility is allowed to retain little or no part of its earnings, it is more likely to choose options on the basis of cost alone.

Regulatory Treatment of Options

The choice of an option, it has been noted, is governed not only by its cost, technological performance, and effect on the existing system, but by the regulatory treatment of each of these factors. In addition to the issues already mentioned, others merit discussion.

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[4] Ibid.

A utility subject to traditional rate-of-return (ROR) regulation characterized by strong oversight and scrutiny in the form of prudence reviews and strict application of the "used-and-useful" standard is likely to favor those options that minimize regulatory risks rather than those having the best potential to minimize overall costs. For example, scrubber technologies generally have higher capital costs relative to other options, but exhibit a lower operating cost.[5] A utility is, however, likely to shy away from scrubbers if it perceives a significant risk of future disallowance of investment costs. At the other extreme, if a state commission preapproves a compliance plan, it relieves the utility of any significant risk of underrecovering its costs and impedes future adjustments or innovations that would improve the efficiency of the system within the preapproval period (this limitation to preapproval is discussed more fully in Chapter 6). The effect can be dramatic if allowance prices turn out to be low relative to scrubbing costs, and the preapproved compliance plan included significant investments in scrubbers.[6] The effect of regulatory treatment on the decisions of a utility is the main focus of Chapters 7 and 9.

Future Allowance Prices

Perhaps the most critical factor governing the choice of a compliance strategy is the expected price of emission allowances and its attendant uncertainty. In Chapter 1, the effect on the choice of compliance option of the assumed allowance price was demonstrated. This provided a simplified and static approach to optimal compliance planning under the projected scenarios of high, medium, and low allowance prices relative to the costs of various compliance options. The conclusions regarding the role of allowance prices derived from the simple illustration would generally be valid even if actual compliance planning would involve significantly more complex analysis. One such

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[5] Ibid., Part II, III-5.

[6] The effect of ratemaking on compliance choices is discussed in more detail in Chapter 7. The issues of prudence and preapproval are discussed in Chapter 6.

conclusion is that a utility should only use compliance options that have unit incremental costs lower than the allowance price and only when all such options are exhausted should it purchase allowances to meet any remaining compliance requirements. What makes more complex analysis essential is the fact that a compliance plan or strategy has to be designed *before* any of the costs or prices and regulatory treatment of any of the related expenses are known. The utility's compliance strategy needs to account for such uncertainties and their attendant risks. Also, since the expected price of allowances becomes more uncertain over time, any strategy that relies on purchasing allowances, that is, one that requires the purchase of a stream of allowances over time, would have to factor this temporal uncertainty into the analysis.

Uncertainties and Risks

Each of the factors discussed so far involves market-related uncertainties and risks. The impact of uncertainties was dramatically demonstrated during the 1970s when electric demand failed to grow according to earlier forecasts resulting in a large number of utilities being burdened with excess capacity and stranded investments. The utilities may be faced with the same difficulties if future load growth, fuel prices, capital and operating costs of emission control technologies, and allowance prices depart significantly from forecasts used to develop compliance plans.

Developing an Optimal Compliance Strategy

The General Approach

To develop an optimal compliance plan, the general approach of solving any forward-looking optimization problem can be used. That means defining an objective function or performance index to be optimized (maximized or minimized), choosing the decision variables that constitute the utility's menu of choices, identifying the constraints that must be met, and finally setting the planning horizon over which the optimization is to take place.

In the case of clean air compliance, there are a number of choices for the objective function. Two such choices that immediately suggest themselves are the net or incremental cost of compliance and the net cost of generation (including the cost of compliance). Given the adoption of the least-cost standard by most state commissions, it is reasonable to assume the latter (net cost of generation) is a more appropriate choice for an objective function.

The constraints include the electric loads that must be satisfied, the emission caps that must be met, other environmental requirements to be met, and constraints imposed by scheduled plant maintenance and unscheduled plant outages.

The planning horizon can be as short as one year or as long as thirty (or more). Choosing either short or long planning horizons has its respective advantages and disadvantages. Shorter planning horizons mean that the actual conditions are unlikely to deviate significantly from forecasts. The disadvantage is that short-term compliance plans are likely to turn out to be suboptimal over the long run. This becomes critical when compliance choices involving either long construction periods or long payback periods are excluded, even when they are optimal because a short planning horizon is chosen.

Use of a longer planning horizon captures the cost savings and benefits of investments with long payback periods. However, a long-term plan is more sensitive to forecast errors and uncertainties. Another factor to consider is the lack of flexibility with respect to large investments that may involve either long construction periods or long useful lives. Investments in options with long construction periods may be faced with premature abandonment if the investment, for example, on hindsight turns out to be imprudent. Options that have long useful lives may have to be written off prematurely if the costs of continuing to operate them become prohibitive relative to other options. In both cases, a state commission may be confronted with the predicaments of allocating the costs of abandonment of a project that is either incomplete or completed but underutilized and of having to decide the appropriate recovery of such costs.

An optimal compliance plan needs to account for uncertainties and risks inherent in implementing any forward-looking plan.

Accounting for Uncertainties and Risks

The need to account for uncertainties and risks in utility planning has been recognized following the failure of many planning parameters to meet forecasts in the 1970s and early 1980s. More important among these parameters include load growth, fuel prices, construction lead times, and inflation rates. When considered in the context of least-cost and integrated resource planning, other parameters subject to uncertainty include customer response to DSM initiatives, costs of DSM options, potential energy savings from DSM measures, and regulatory treatment of DSM options. To this list of uncertain parameters a utility planner devising a clean air compliance plan must add all construction and operating costs of compliance, technological performance, allowance prices, and the regulatory treatment of compliance costs and savings.

Uncertainties mean that a unique "least-cost" plan cannot be defined, since a plan which achieves the lowest cost under some circumstances may perform poorly under others.[7] It is now generally held by utility analysts that a utility plan should be "robust" enough to perform reasonably well under many possible scenarios and circumstances although it may not be the best plan under any one of them.[8] Several methodological approaches are available to address the problem of planning under uncertainty.[9]

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[7] Eric Hirst, *Regulatory Responsibility for Integrated Resource Planning* (Oak Ridge, TN: Oak Ridge National Laboratory, 1988).

[8] Narayan S. Rau, Mohammad Harunuzzaman, Daniel J. Duann, Benjamin Hobbs, and Pravin Maheshwari, *Uncertainties and Risks in Electric Utility Resource Planning* (Columbus, OH: The National Regulatory Research Institute, 1988), 23.

[9] Howard Raiffa, *Decision Analysis: Introductory Lectures on Choices Under Uncertainty* (New York: Random House, 1968).

Methods that Optimize Expected Values

These methods attempt to formulate the objective function as an expected value or statistical expectation rather than as a precise value to be determined. The general approach of these can be illustrated using a decision tree. Figure 4-3 is a decision-tree representation of the clean air compliance problem when future reduction requirements, compliance costs, and emission allowance prices are uncertain.[10] This assumes that the planning process is risk-neutral.

The decision tree shows the utility can choose to overcomply significantly, only moderately, or not at all. For each of these choices, there are certain probabilities for each future event such as high or low reduction requirements, high or low compliance costs, and high or low allowance prices. Each of these probabilities is shown as decimal numbers next to the fork associated with a given event. Each of the endpoints, labelled as a whole number, represents a possible outcome. The expected value of some objective function, such as net compliance cost, can be calculated for each endpoint.[11] The expected cost of each option is the sum of expected costs of all endpoints originating from that option. For example, the option labelled "significant overcompliance" has an expected cost which is the sum of expected costs of endpoints 20 through 27. The option with the lowest expected cost will be chosen.

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[10] Reduction requirements depend on load growth. Future reduction requirements are uncertain because load growth is uncertain. The decision tree example is taken from Electric Power Research Institute, *Clean Air Response*, Part II, II-28.

[11] For example, the expected cost of compliance for endpoint 16 is (0.5 x compliance cost in $/ton) (actual reduction in tons) - (0.3 x allowance price in $/ton) (0.5) (actual reduction in tons - required reduction in tons).

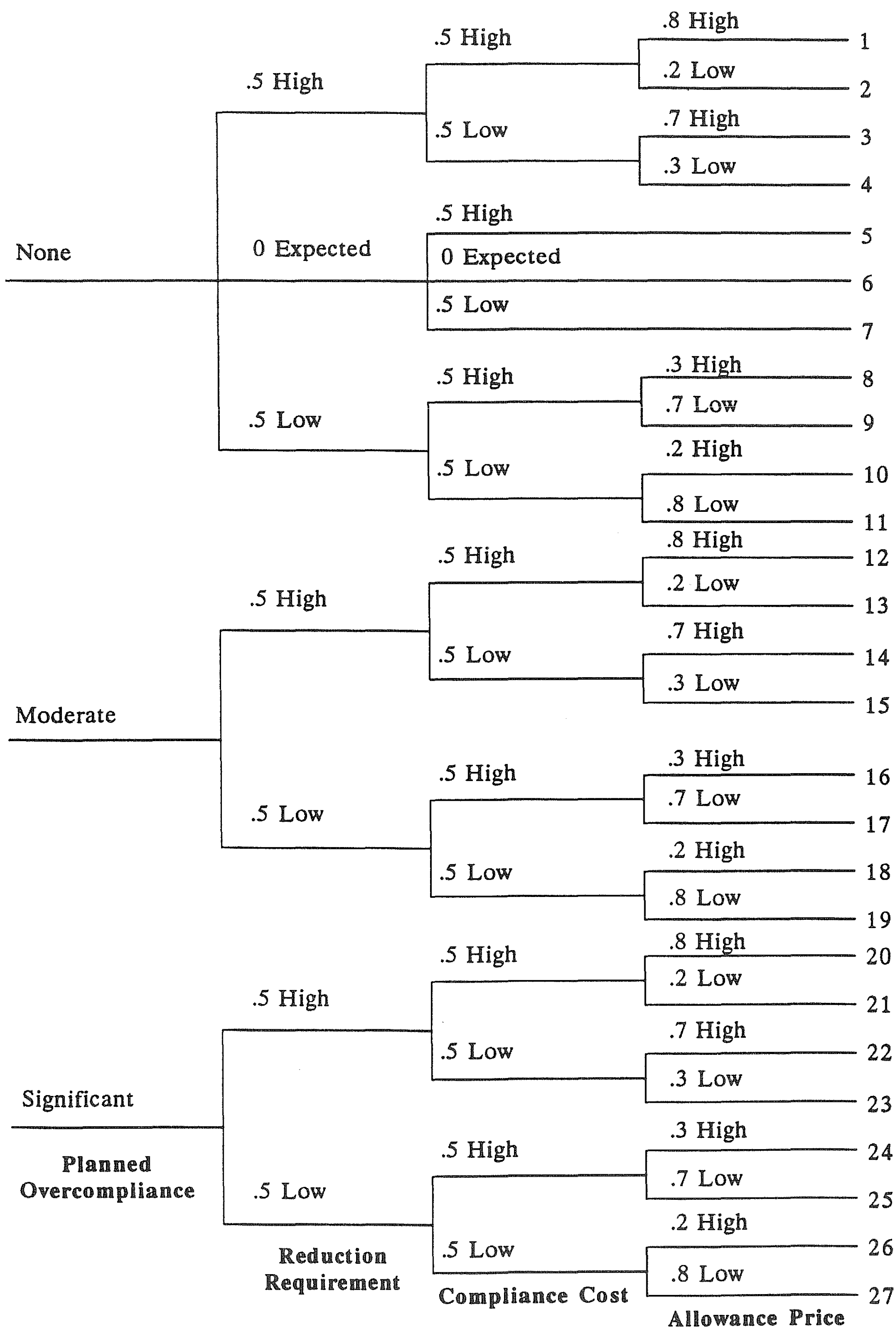

Fig. 4-3. **A decision tree of compliance options** (Source: Electric Power Research Institute, *Clean Air Response*, 1990).

Methods that Minimize Risks

These risk-minimizing methods reflect a risk-averse approach to planning and have their origins in financial portfolio management analysis.[12] The objective is to minimize risk by bounding the range of possible outcomes, rather than maximize expected profits or minimize expected costs. One widely used method is to minimize the statistical variance (a measure of uncertainty) of some objective function. In the compliance planning context, this can translate into minimizing the variance of the net compliance cost or the net generation cost.

The Role of Flexibility in Compliance Planning

Flexibility can improve performance when actual events diverge from expectations. Explicit consideration of flexibility is appropriate in utility planning. The more latitude the utility has during the course of implementing a plan to introduce changes, the easier it is to respond to events as they materialize. Some options are less amenable to such "midcourse correction" than others. Building scrubbers, for example, locks up a large amount of capital and makes it difficult for the utility to abandon this option or switch to other options in the future.[13] It is also difficult to switch *to* scrubbers if none are in place already, even when it is desirable economically to do so because of the relatively long construction time involved. At the other extreme, the liquidity of emission allowances should make buying and selling them easy in response to market conditions and costs of other options. Indeed, if flexibility were the only criterion, perhaps a utility would never opt for scrubbers. But one cannot ignore the possibility that allowance prices may, indeed, be high relative to scrubbers. This

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[12] H. Levy and M. Sarnat, *Portfolio and Investment Selection: Theory and Practice* (Englewood Cliff, NJ: Prentice-Hall, 1984).

[13] Steven Mitnick, "To Scrub or Not to Scrub: The Hidden Risks of Inflexibility," *The Electricity Journal* (January/February, 1992): 44-49.

possibility, coupled with the fact that building scrubbers has superior economies of scale, makes it imperative that a compliance plan does not exclude scrubbers, and any other option for that matter, on the basis of a single criterion.

The best possible approach is to build enough flexibility into a compliance plan to allow a utility to respond well to all predicted scenarios. The flexibility of any individual option or technology is less important than the flexibility of the total plan. The methods that optimize expected values or minimize variances already allow some of this desired flexibility to be incorporated. They, however, do not adequately capture the value of flexibility or provide a precise standard for comparing the flexibility of different compliance plans. This is due to the fact that unlike expected values or statistical variances, a precise, quantifiable, and commonly accepted definition of flexibility is as yet unavailable. A qualitative assessment of flexibility, based on the planner's experience and best judgement, may have to be used to evaluate compliance plans. Even the best quantitative evaluations do not capture all the relevant variables and factors, and need to be supplemented with good judgement to design effective compliance strategies.

Compliance Survey

In the fall of 1991, the NRRI conducted a survey of state public utility commissions on their actions concerning the CAAA. The survey questions focused on the activities of four groups: state public utility commissions, utilities in their jurisdiction, state legislatures, and environmental or related state agencies. The summarized responses to this survey are in Appendix C.

Most of the state public utility commissions have undertaken some action concerning compliance with the Title IV provisions of the CAAA. Over half of the responding commissions have conducted staff training on CAAA requirements. Nearly 40 percent of the respondents indicated that they have begun a preliminary review of draft electric utility compliance plans. Almost a quarter of the respondents have begun developing policies for the regulatory treatment of allowances, but most have not drafted rules or procedures yet. Twenty percent either have sponsored a workshop or opened generic cases on the subject. A little over a quarter of the responding commissions have taken no action to date. One action that is decidedly not on the commissions' agenda is limiting utility activity in an SO_2 emissions allowance market: 95 percent of the respondents said they were contemplating no such action.

Two issues were generally identified as the most important from the standpoint of the commissions in addressing the implementation of Title IV. First was the integration of least-cost planning and integrated resource planning with CAAA compliance. The second major issue was the regulatory treatment of emission allowances (for example, determining the market value and allocating the allowances between ratepayers and shareholders and between operating and holding companies). Several other issues were raised, including the economic effect of compliance on rates and on other industries, especially coal mining, the coordination with state and federal environmental protection agencies and other commissions in multistate matters, and the environmental effect of secondary wastes.

Only 20 percent of respondents felt that implementation of the Title IV provisions would not require their commissions to undertake new activities or adopt new methods. Not surprisingly, over half of the respondents stated that their commissions would have to develop regulations covering the treatment of allowances. Almost 40 percent felt there is a need to alter their current integrated resource planning process. Almost a quarter of the responding commissions indicated that they would initiate or change the preapproval process to accommodate compliance plans.

Although the concern is high, most responding commissions had not begun formally to consider how shareholders and ratepayers will be allocated the costs and benefits of compliance with Title IV requirements. Five commissions (Delaware, Florida, Illinois, Maryland, and Pennsylvania) reported that current decisions would have some bearing on this issue. Eighty-six percent of the respondents said that their commission has not decided or begun to consider how to treat costs and revenues related to SO_2 emission allowances for ratemaking purposes. Although multistate issues were not frequently cited as a major issue, over 90 percent of the respondents anticipated having to address interstate or multistate issues. Several standing coordinating vehicles appear to be in place already for some commissions. Examples include the AEP Regional Coordinating Committee (with six state members), the Power Planning Committee of the New England Governor's Conference, and the PacifiCorp Interjurisdictional Task Force on Allocations (PITA).

Over half of the responding commissions have not undertaken research projects concerning the implementation of, or compliance with, Title IV provisions. Of those currently involved in research, cost-benefit studies of fuel-switching and conservation and renewable energy were frequently cited. However, many commissions indicated that while they were not currently conducting research themselves; instead, they were monitoring information on the subject. To assist their commissions in decision-making on Title IV implementation, commission staffs appeared to favor newsletters and training workshops and seminars almost two-to-one over electronic bulletin boards and PC-based compliance planning models. However, the latter two sources of information were requested by over 40 percent of the respondents.

Almost two-thirds of the responding commissions reported that utilities in their jurisdiction have at least identified the specific units affected by Title IV provisions. Almost half of the respondents say the utilities already have proposed or stated what action will be required to comply with the CAAA. Over a quarter of the respondents have received systemwide compliance plans, compliance options analyses, or had the affected utilities indicate how allowances would be used.

Most states apparently do not have preexisting statutes that are in conflict with, or inconsistent with Title IV. As a result, 83 percent of the respondents reported no legislative activity addressing this issue. The others have reconciled their laws with the CAAA. The state air agencies appear to have imposed few requirements on utilities since the CAAA enactment. Finally, most commissions are or anticipate interacting--at least informally--with their respective state air agency regarding issues associated with the Clean Air Act compliance.

CHAPTER 5

STATE/FEDERAL INTERACTION AND MULTISTATE ISSUES

Section 403(f) of the CAAA leaves federal and state jurisdictions unaffected by Title IV, the emissions trading provisions. Specifically, the section states that

> . . .Nothing in this section shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges or affecting any State law regarding such regulation or as limiting such a State regulation (including any prudency [sic] review) under such a State law. Nothing in this section shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under that Act. Nothing in this title shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established. . .

The CAAA maintains existing state and federal commission jurisdiction for the oversight of utility compliance with emissions trading provisions. As one commentator stated "the Congress punted on how the EPA and the emissions trading provisions would fit in with state public service commissions and the Federal Energy Regulatory Commission."[1]

With existing state and federal jurisdictions maintained, the CAAA creates a new opportunity for state commissions to cooperate among themselves and with the FERC. Should this opportunity not be realized, a new area of jurisdictional conflict could result. Under a "business as usual" scenario, the FERC would have clear jurisdiction over registered multistate holding companies operating centrally dispatched systems and having capacity and energy allocation agreements approved by the FERC. Registered multistate holding companies could amend their allocation agreements to provide for the equitable division of compliance costs. Although there may be no explicit statutory

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[1] Reinier Lock at The National Regulatory Research Institute's Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990, Arlington, Virginia, January 31, 1991.

authority for it, the FERC could possibly preapprove the costs of CAAA compliance. As result of the preemption doctrine, passthrough of expenses to the state commissions would be required, possibly without a thorough prudence review. Under this scenario, state commissions cannot second-guess FERC decisions on matters covered by such allocation agreements.[2]

Registered multistate holding companies could also amend their allocation agreements to provide for the equitable division (allocation) of emission trading allowances among member companies. FERC's policies could significantly affect the allowance market because the nine existing registered multistate holding companies under the FERC's jurisdiction will have 25 percent of the allowances by the year 2000.

A registered holding company petitioning the FERC to amend its allocation agreement or submitting a new one would be subject to a hearing to decide whether the agreement was just and reasonable, nonpreferential, and not unduly discriminatory under the Federal Power Act.[3] State public service commissions could be parties to such a hearing. Most (about 90 percent) of FERC's cases result in a settlement. If, for example, a case dealing with amending an allocation agreement to distribute allowances was settled, it is likely that state commissions would have ample opportunity to participate in the FERC settlement process and seek a prudence review of subsequent utility expenditures of the costs of CAAA compliance.

Multistate utilities or a pool of utilities that are not registered holding companies could apply for an exemption from state regulation if they meet the provisions of PURPA § 205 and FPA § 205. To be exempt the utility must show that state law

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[2] Mississippi Power & Light Co. v. Mississippi Ex Rel. Moore, 108 S.Ct. 2428 (1988).

[3] Federal Energy Regulatory Commissioner Charles Trabandt noted that FERC's jurisdiction over allocation agreements is not discretionary. If a plan or an amendment to a plan is filed, the FERC must take jurisdiction over the matter. Charles Trabandt, "State/Federal Issues: FERC Review of Multistate Utility and Holding Company Compliance Plans," presented at the NRRI Workshop on Developing Public Utility Commission Rules and Procedures for Electric Utility Compliance with the Clean Air Act Amendments of 1990 for Midwestern States, St. Louis, Missouri, May 8, 1992.

prevents voluntary utility coordination, including central dispatch, if the coordination is designed to achieve economical use of facilities and resources in the area. In effect, the utilities must show that they have formed a power pool. No exemption is permitted if state law is designed to comply with federal law or to protect health, safety, welfare, or the environment; to conserve energy; or to mitigate the effects of an energy shortage. However, a state commission could argue its oversight of CAAA compliance plans and allowance trading does not prevent the voluntary coordination of utilities if the regulation requires least-cost compliance planning, including buying and selling emissions allowances when economically feasible. As an integral part of a state commission's least-cost planning process, economic regulation of allowance trading would be designed to protect the health, safety, welfare, and the environment as well as to encourage economic conservation of energy.

Federal Power Act § 205 requires power pool interconnection agreements to be filed with the FERC. While power pool agreements developed prior to passage of the Clean Air Act Amendments do not explicitly deal with allowances (whether or not in an allowance pool), utilities in a pool might file amendments to their pool agreement with the FERC to specify the treatment of allowances.

A third, significant context in which FERC jurisdiction might arise is wholesale power sales. The Federal Energy Regulatory Commission has jurisdiction over the wholesale power market for both requirements and coordination sales. FERC would tend to have jurisdiction over any allowances associated with wholesale power sales, subject to a possible "Pike County review" of the prudence of the wholesale purchase decision (but *not* the price) by the purchasing utility.

One might expect that the FERC would graft the price of allowances onto its existing policies of having cost-based rates for requirements customers and most coordination sales, and market-based rates available for coordination sales where the seller demonstrates that neither it nor its affiliates have market power in generation or transmission, or that such market power has been adequately mitigated, and that the seller has not engaged in "affiliate abuse." However, because the tying of allowances to bulk power sales might lead to a less liquid and transparent allowance market, as well as bulk power market, the FERC might choose to require that purchases of allowances be unbundled from wholesale power sales.

Without federal preemption of unregistered multistate utilities and holding companies, inconsistent CAAA compliance planning strategies among state jurisdictions are possible. Disagreements could also arise between states on jointly owned plants and other multistate utilities. These inconsistencies could lead to trapped, unrecovered costs, double recovery of costs, or the inability of the utility to comply with an effective CAAA compliance plan because of conflicting regulatory requirements.

In this new context, state commissions and the FERC may find it useful to explore methods of regional regulation. Regional regulation could be as formal as a state compact, but could also entail informal agreements among states, a conference to develop regional uniformity, or other methods, such as joint state problem solving workshops, information trading on a regional basis, and consultative mechanisms between state commissions and the FERC. Collaborative and innovative administrative procedures would enhance the ability of agencies to cooperate with one another. (Some available procedures are reviewed in a previous NRRI report.[4]) The objective should be consistent treatment to the extent possible among the states in a regional context, particularly for multistate utilities.

Any regional regulation approaches placed into operation should not simply become another layer of regulation. Regulators need to reach an agreement on a uniform approach to utility compliance planning to avoid this outcome. If a form of regional regulation among state commissions (and with the FERC where registered multistate holding companies are involved) were in place, the result may be a more liquid, transparent, and smoothly operating emissions trading market. To encourage such regional regulation and coordination, FERC Commissioner Charles Trabandt suggested

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[4] Robert E. Burns, *Innovative Administrative Procedures for Proactive Regulation* (Columbus, OH: The National Regulatory Research Institute, 1988).

that "FERC regulators should exercise maximum reasonable regulatory restraint *at this time*."[5]

Options for Regional Regulation

As just noted, in speaking about regional regulation the authors use the term in its broadest sense. Regional regulation is any means by which state public service commissions, and the Federal Energy Regulatory Commission where appropriate, can regulate on a multistate, regional basis.[6] Regional regulation spans a host of options, from informal, ad hoc state coordination on individual issues, through more stable coordination efforts of state commissions to share information and act in tandem when mutually beneficial, to more formal mechanisms such as a FERC-state joint board mechanism or a congressionally approved compact establishing a regional regulatory body.[7]

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[5] Charles Trabandt at The National Regulatory Research Institute's Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990, Arlington, Virginia, January 31, 1991. For a complete text of his remarks see, "Remarks of Charles A. Trabandt, Commissioner Federal Energy Regulatory Commission," *NRRI Quarterly Bulletin* 12 no. 2 (June 1991): 209-16.

[6] At least one commentator has denounced the idea of regional regulation. See Charles A. Patrizia, "Regional Solutions to Power Supply Planning and Clean Air Act Compliance on a Multistate Utility System--A Solution in Search of a Problem?" presented at the Fifth Annual American Bar Association Conference on Electricity Law and Regulation, Denver, Colorado, March 12, 1992; and Charles A. Patrizia, John Rice, and Greg Wortham, "Can the Arkansas-Entergy-New Orleans Regional Planning Body Pass Muster? No," *The Electricity Journal* (January/February 1991): 40-43. However, when examining his remarks one finds that he is against regional regulatory compacts, such as the Entergy plan, but is supportive of more informal regional regulatory mechanisms.

[7] For a full explanation of these regional regulation options, see Douglas N. Jones et al., *Regional Regulation of Public Utilities Issues and Prospects* (Columbus, OH: The National Regulatory Research Institute, 1980); and Linda G. Stuntz, "Is It Time to Consider Regional Solutions to Power Planning Problems? One Federal View," *The Electricity Journal* (January/February 1992): 14-19.

Each of these regional regulatory options has advantages and disadvantages. For example, informal, ad hoc coordination by states on a single issue might be unlikely to provide state commissions with the degree of oversight they might desire, particularly if the utilities in question are either a registered multistate holding company or are involved in an allowance pool. More stable coordination efforts by state commissions, such as the New England Conference of Public Utilities Commissions (NECPUC), have the potential advantage of allowing state commissions to coordinate their policies and exchange information about emission allowances. Further, if there were a case for an allocation of allowances brought before the Federal Energy Regulatory Commission by a multistate regional holding company, the FERC has indicated that it would give substantial deference to any voluntary arrangements negotiated among the affected states.[8] However, such voluntary, albeit stable, arrangements are no stronger nor more effective than the degree of agreement between the state commissions. In these circumstances, the will of a majority or a supramajority of commissions would not be binding on a minority or lone dissenter. Further, even when there is substantial agreement among the state commissions, circumstances arise where emission allowance issues might be brought before the FERC. Even if the FERC were to give substantial deference to voluntary agreements of state commissions, state commissions technically have no greater standing in a FERC settlement proceeding than any other intervenor.

Two additional formal regional regulation mechanisms are federal-state joint boards and conferences, and a congressionally approved regional regulatory compact. Some have criticized these options as merely adding another layer of regulation or replacing existing voluntary and flexible arrangements with rigid, formalistic structures that shift authority from federal and state officials to regional bodies of uncertain authority and accountability.[9] A joint federal-state board is an option provided by the

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[8] See Northeast Utilities Co. (Re: Public Service Co. of N.H.), 58 FERC para. 61,200 (1992).

[9] See Stuntz, "Time to Consider," 19; and Patrizia, "Regional Solutions to Power Supply Planning."

Federal Power Act § 209. However, this option has never been used by the FERC and would, therefore, need to be developed. For example, § 209 authorizes the FERC to "refer any matter arising in the administration of (Part II of the FPA) to a board composed of a member or members, as determined by the Commission, from the State or each State affected or to be affected by such matter." A narrow reading would let the FERC use the joint board mechanism only for FPA matters exclusively within its jurisdiction. State commissions could be represented on the joint board if they currently are affected or expect to be affected by the matter.

It is unclear what the jurisdictional powers of the joint board would be concerning matters over which the FERC and states have concurrent jurisdiction. Also, there might be an understandable reluctance to give up any decisionmaking authority (even if it is nonbinding) to representatives of state commissions when FERC can maintain authority and have the state commissions represented as intervenors in the more typical FERC settlement proceeding. The Federal Communications Commission has been effective in using its Federal Communications Act § 410 joint board powers to avoid outright federal preemption in areas where state and federal jurisdiction are concurrent. The FERC also might find it useful to explore its joint board powers as an alternative to federal preemption. Another option is for the FERC to use a joint-board-style mechanism to convene the states while requesting the Secretary of Energy to appoint a facilitator to help the parties find a solution to regional problems. The Secretary of Energy's role would be consistent with his role as voluntary coordinator of energy policy as assigned to the Secretary by the Department of Energy Act of 1977.[10]

The other option for regional regulation is the congressionally approved multistate compact, which might be desirable for state commissions that want to regulate the emission allowance trading of a regional holding company as a group. As pointed out elsewhere in the report, state commission regulation of allowances probably makes sense

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[10] This suggestion was made by Charles Curtis, "Maintaining a Proper Balance Between Federal and State Authority--Is There a Place for Regional Regulation?" *The Electricity Journal* (January/February 1992): 32-33.

in the context of integrated resource planning. Recently, there has been a proposal for a congressionally approved regional compact that would allow for regional integrated resource planning by the City of New Orleans and the affected states, with FERC approval.[11] Use of a regional regulatory compact has the advantage of allowing state commissions to act consistently as a group on emission allowance trading policies, perhaps as a part of integrated resource planning. However, it has the disadvantage of needing congressional approval. It is possible that a bill allowing for a compact in a format acceptable to the state commissions would not survive congressional debate. Also, because compacts are voluntary organizations not all of the states might choose to belong. Finally, some opponents have claimed recently that because a compact is a matter of federal law when it comes to determining whether a federal court has jurisdiction over a case (that is, a compact raises federal questions that can be tried in a federal court) appointments to a compact must be federal officers appointed according to the Appointments Clause of the Constitution. The Appointments Clause requires that all federal officers be nominated by the President and confirmed by the Senate, appointed by the President alone, or appointed by the Judiciary or heads of departments.[12] However, a United States Court of Appeals case rejects this argument because state members to a compact ultimately empower their members to carry out their duties. Virtually all existing compacts have members appointed by participating states.[13] In either event, belonging to a federally approved state compact requires state commissions to yield a degree of autonomy and state sovereignty, which has the effect of diminishing a state commission's ability to take into consideration local concerns.

Some degree of regional regulation, whether formal or informal, appears to be appropriate for state commissions that need to deal with regional emission allowance

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[11] S2607. See "Johnston Offers Utility Regional-Planning Bill; May Hearing Likely," *Inside F.E.R.C.* (April 20, 1992), 2-3.

[12] See Patrizia, Rice, and Wortham, "Can the Planning Body Pass Muster?"

[13] Seattle Master Builders v. Pacific Northwest Electric Power and Conservation Planning Council, 786 F.2d 1359 (9th Cir. 1986).

trading issues. Further study of regional regulation theory and structure must be conducted before providing state commissions with more guidance of which regional regulatory option might be worthy to pursue.[14]

Tax Treatment of Allowances

The tax treatment of emissions allowances, while as yet unknown, will have important regulatory implications.[15] The tax decisions that the Internal Revenue Service makes will affect utility behavior and the regulatory treatment of the allowances.

The primary tax issues involve the receipt of the allowances, the sale or exchange of allowances, and the purchase and cost recovery of allowances. What follows is some speculation as to the most likely tax treatment of allowances.

Receipt of Allowances

One would normally expect the receipt of allowances to be regarded as a taxable event, because the emission allowances have value and are expected to be traded and to have a market-based price. However, most phase I and phase II initial allowances will be issued to utilities based solely on their baseline fuel use. No income is received unless the allowances actually increase net worth. Thus, the receipt of the basic emission allowances is not likely to be regarded as taxable income. Rather, it is a zero-basis intangible asset on the utility's tax books until used internally or sold when, of course, it

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[14] The National Regulatory Research Institute has undertaken such a study which is scheduled for completion later this year.

[15] This section of the discussion draws freely on the presentation of Donald W. Kiefer on "The Tax Treatment of Emission Allowances," presented at The National Regulatory Research Institutes Workshops on Emission Trading in Arlington, Virginia, January 30, 1991, and Chicago, Illinois, May 9, 1991. The reader can obtain a copy of the presentation from NRRI.

has a value. This approach is analogous to that used in EPA's program of lead rights trading which existed from 1982 through 1987.

Besides emission allowances received by utilities as a means of imposing the basic emission tonnage limits, there are three other areas of concern. First are the allowances withheld for the EPA Administrator's reserve for auction. These should raise no tax consequences when withheld, and if returned in the form of allowances should present no tax consequences at that time. However, if the allowances are sold from the reserve and returned as income from their sale, that income would be taxable.[16]

Second, extra "bonus" allowances will be given to some utilities during phase I and phase II under §§ 404 and 405. Tax treatment of these bonus allowances will be more problematic. Under phase I, utilities in Illinois, Indiana, and Ohio are to receive pro rata shares of a pool of 200,000 extra allowances annually. In addition, there are extra allowances for early reductions and for 90 percent removal scrubbers. Extra allowances also are to be given for emissions avoided through energy conservation programs and renewable energy sources.

Under phase II, a pool of 50,000 allowances annually will be shared on a pro rata basis by utilities in ten states, including the three pool-sharing states under phase I. There also is a special pool of 125,000 bonus allowances annually to be divided among utilities in "clean states." Finally, there is a larger pool of bonus allowances available for allocation to utilities in certain "high growth states."

One way to consider these bonus allowances is as a nontaxable, selective means of relaxing the generally stated emissions limitations. Another way that is perhaps more likely is as subsidies to help defray extraordinary pollution control cost and induce extra pollution control efforts. If viewed as subsidies, the allowances would be considered taxable income equal to their market value at the time they were received. Alternatively, if bonus allowances are used to subsidize investment in specific pollution

[16] If a utility must purchase allowances to replace those withheld for EPA's reserve, the cost of the allowances may be netted against the proceeds of the sale of the withheld allowances as an involuntary conversion.

control assets such as scrubbers, the basis of the assets might have to be reduced by the value of the allowances.

The Sale or Exchange of Allowances

A second taxable event occurs when the allowances are sold or exchanged. Sold allowances are likely to be considered capital assets under § 1221 of the Internal Revenue Code. As such, proceeds from the sale in excess of the tax basis would be taxed as a capital gain. Likewise, any excess of basis over the sales proceeds would be a capital loss.

The basis is likely to be zero for allowances received as part of the initial phase I and phase II distribution. If the receipt of bonus allowances is taxed, the basis would be the imputed (pretax) value of the allowances at the time of receipt. The basis for purchased allowances would be their cost.

Section 1030(a) of the Internal Revenue Code--the "like-kind exchange provision"--might allow exchanges of allowances usable in different years without any gain or loss on the exchange. If so, the allowances received in such a trade would assume the basis of the traded allowance.

The capital gains or loss treatment of allowances would make EPA recording and tracking of allowances important, even though the agency might choose not to develop specific inventory rules. A company holding allowances might prefer to determine which allowances are sold when, and hence determine their basis for the sale. Alternatively, the IRS may require a recognized accounting procedure such as first-in, first-out or some sort of average approach. The tax code allows last-in, first-out and certain other inventory methods so long as the same method is used in the firm's financial reports.

The primary tax issue when emission allowances are purchased is what kind of asset the allowances represent to the purchaser. This determines the type of cost recovery. The most widely held view is that emissions allowances should be deducted against the income they are used to produce on an as-used basis. How to derive this under the tax code is uncertain. One possibility is to view the allowance either as an inventory assist or as a deferred expense--(IRC § 461(h))--to be deducted in the year used. Another appealing possibility is that the allowances might be considered intangible assets with no fixed life that are written off in the year they are exhausted or used.

A less desirable treatment (that is, having a higher tax liability) is that the allowances be viewed as an intangible asset to be amortized over an assumed useful life.

Interperiod tax accounting issues could arise if tax and ratemaking treatments of allowances differ, particularly where allowances (specifically bonus allowances) are taxed on receipt, where state commissions allow recovery on allowances purchased and banked for future use, and where regulatory commissions do not allow rate base treatment of investments in overcontrol compliance strategies.

Recent Developments

After a letter request by the Edison Electric Institute for a Revenue Ruling on February 27th, 1992 the Internal Revenue Service issued Advance Revenue Ruling 92-16. It holds that the allocation of emission allowances by the Environmental Protection Agency pursuant to § 7651(b) does not cause a utility to realize gross income under § 61 of the Internal Revenue Code. In addition, under § 1013 of the Internal Revenue Code, a utility's basis in those emission allowances is not measured by reference to the market price of allowances.[17] The only reasonable interpretation is that the initial allocation of allowances by the EPA to the utility is not a taxable event, and that their taxable basis is zero. As noted later in this report, such an interpretation could tend to result in uneconomic banking (that is, hoarding). This would occur because there would be a weak incentive for the utility to realize a capital gain by selling the allowances. With a zero basis, a profit on the sale of an allowance would be certain so long as the allowance had any market value at all.

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[17] See "IRS Issues Ruling on Emission Allowances," *Public Utility Executive Briefs* (Washington, D.C.: Deloitte & Touche, 92-2, February 28, 1992), 1-2; and Internal Revenue Rul., *Internal Revenue Bulletin*, 1992-12 (March 23, 1992).

Also on February 27th, the IRS issued a Notice for Public Comment on the federal income tax consequences of emission allowance trading transactions, pursuant to Title IV of the Clean Air Act Amendments of 1990.[18] The IRS requested comments on the following issues: (1) How are the costs of acquiring emission allowances treated for federal tax purposes? (2) What costs, if any, are included in the tax basis of an allowance? (3) Is the cost of acquiring emission allowances an indirect cost of producing property under Internal Revenue Code § 263A? (4) Can allowances be depreciated under § 167? (5) When and how would a taxpayer recover its basis in an emission allowance in each of the following circumstances: (a) a utility uses an emission allowance during a year, (b) a utility sells or exchanges an emission allowance, (c) a purchaser of an emission allowance which is not a utility sells or exchanges the allowance, (d) an emission allowance becomes worthless? (6) What is the character of any gain or loss realized in situations (b) through (d) in question 5? (7) Is an exchange of emission allowances a taxable event, and if so, are allowances issued in different years like-kind property under Internal Revenue Code § 1031? (8) Is a penalty paid to the EPA for emissions in excess of allowances deductible under IRC § 162(a)? (9) Will a secondary market be established for trading forward or futures contracts on emission allowances? (10) What is the likely accounting treatment of emission allowances; for example, will separate accounts be established for allowances held for use in electricity production and for allowances held for investment? and (11) What are the tax consequences of participating in the Environmental Protection Agency's emission allowance program by taxpayers who are eligible to opt-in?

The IRS invited all interested parties to comment on any or all of these or related issues, but especially solicited the comments and view of utilities affected by the emission trading program.

The comments on these tax issues will significantly affect how well the emissions trading program works. For a healthy and "economically sound" emission allowance

[18] Ibid. Comments are due thirty days after the date of publication of the Notice for Comments in the *Federal Register*.

trading market to develop, any regulations promulgated by the IRS should be consistent with the intent of Congress to encourage allowance trading when and where economical. Indeed, the greatest "threat" to successful implementation of the EPA's emission allowance trading program may be the tax treatment of allowances by the IRS.[19] For an emission allowance trading program to work in an economically sound fashion, the tax consequences of different utility compliance strategies that involve the use, sale, or exchange of allowances initially allocated by the EPA should be neutral. To achieve this goal, first there must be a recognition that the revocable license granted by the EPA did not provide utilities with anything of value that they did not already have. The allowances merely provided utilities that were emitting sulphur dioxide with a revocable license to continue to do so. As such, there is no tax event on the initial issuance of allowances by the EPA. The IRS has reached this same conclusion.

However, the purpose of the emission allowances is to encourage utilities to trade them so that the overall cost of acid rain compliance is minimized nationally. This can occur only if utilities with a relatively low marginal cost of compliance overcomply and sell excess allowances to utilities with a relatively high marginal cost of compliance. It could be argued that for this to occur, the tax basis of the initial allocation of allowances should not be set at zero. Rather, there should be no tax basis for the initial allocation of allowances until the allowances are used, sold, or exchanged. Then the tax basis for the allowances should be set at the market price for that vintage allowance, which can be best determined when the allowances are sold by the price paid for the allowance. Otherwise, as observed above, a utility may tend to hold or bank their initial allocation

[19] Remarks of Stanley Garnett, Chief Financial Officer, Allegheny Power System made at the "Living With the Clean Air Act Amendments and What's to Come: Utility Planning in the 1990s" Session of the Fifth Annual American Bar Association Conference on Electricity Law and Regulation on March 12, 1992 in Denver, Colorado. One participant at the NARUC Mid-Winter Meeting characterized the lack of "extreme preapproval" (that is, preapproval of expenditures) as the greatest threat to successful emission allowance trading. This argument is countered in Chapter 6 where we show that extreme preapproval may itself be a threat to an economically sound and smoothly working emissions allowance market.

of allowances uneconomically so that no gain will be realized when they are ultimately used by the utility.[20] Sales after the initial sale or exchange would have the tax basis of the allowance reflect the market price or the price paid for the allowance. Unless the IRS promulgates tax regulations consistent with the intent of Congress, it is likely that the emission trading market will not serve its purpose as Congress intended. Technical amendments to the Internal Revenue Code might then be required to accomplish this.

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[20] By uneconomic hoarding, we mean that a utility with a relatively low marginal cost of compliance will be less willing to sell allowances to a utility with a relatively high marginal cost of compliance to the extent where the marginal cost of compliance for all utilities approaches equality. Instead, the utility will tend to hold the allowance for internal use because of its "zero" tax basis. A utility might still be willing to sell allowances if it thinks that its selling price (less the taxes) will be higher than the subsequent repurchase price or if it believes it will never need to use or to replace the allowances.

CHAPTER 6

PRUDENCE, PREAPPROVAL, RISK, AND UTILITY ACCOUNTABILITY

Utility compliance planning is inherently risky. A compliance plan is extremely complex and involves looking fifteen or twenty years into the future. Once a plan is made, it can affect an entire utility system for many years. Utilities face the same uncertainties as in long-term capacity planning, but there are at least two additional uncertainties peculiar to CAAA compliance.

First, increased demand for low-sulfur coal and other substitute fuels is expected to place an as-yet undetermined premium on them. Second, the price of future emission allowances is unknown, making it difficult for utilities to compare the marginal cost of compliance or overcompliance strategies with the expected price of future emissions allowances. Since passage of the CAAA, forecasts of the future price of allowances have varied considerably (the highest price is six times the lowest) and are regarded in general as unreliable.

Since the options chosen by the utility in its compliance plan are highly dependent on the price of allowances, state public service commissions should consider policies that explicitly recognize and try to accommodate this uncertainty. These policies might include allowing utilities to enter into an appropriate portfolio mix of emission allowance contracting arrangements to manage this risk. The portfolio could include long-term, spot, and futures contracts. Of course, these contracts should be subject to some form of state public service commission oversight.[1]

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[1] There are possible parallels between gas supply contract portfolios and the emissions allowance portfolios suggested here. For a discussion of gas supply contract portfolios, see J. Stephen Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches* (Columbus, OH: The National Regulatory Research Institute, 1988). For a discussion of how state public service commissions currently review gas supply contract portfolios, see Daniel Duann, Robert E. Burns, and Peter Nagler, *Direct Gas Purchases by Gas Distribution Companies: Supply Reliability and Cost Implications* (Columbus, OH: The National Regulatory Research Institute, 1989) and Robert E. Burns, Mark Eifert, and Peter Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, 1991). The latter report includes a conceptual framework for a light-handed approach for commission review of a portfolio of supply contracts that relies on incentive compatibility to assure the utility utilizes a lowest or best cost mix.

A third type of uncertainty faced by utilities, which is not unique to acid rain compliance planning, is the postinvestment or retrospective prudence of a capital expenditure required to comply with the CAAA. In other words, will an investment made by a utility which appeared to be prudent when the decision was made be found by the state public service commission in the future after the fact to be prudent? To avoid an adverse outcome and the harm that can be caused by the fear of it, some have proposed that state public service commissions preapprove compliance plans, expenditures, or both to minimize the chance of this occurring. The ostensible goal of preapproving compliance planning or compliance expenditures is to manage the regulatory uncertainty associated with allowance trading and compliance decisions by not holding the utility responsible for factors beyond its control. There are four major problems with this procedure, which will be dealt with below.

Proponents of preapproval feel utilities are not willing and should not be required to take risks associated with compliance planning unless there are "guarantees" from regulators that utility costs and investments will be recoverable.[2] Otherwise, it is argued, utilities will take a conservative approach, planning for compliance on a stand-alone basis, planning to comply for phase I only, and not overcontrolling for phase II, or choosing a strategy that minimizes risks for shareholders instead of a strategy that minimizes compliance costs. If all utilities were so conservative, the cost of compliance likely would be the same as for command-and-control approaches, and the benefits of a market-based approach would be lost. Guarantees of this sort, however, run counter to at least one hallmark of public utility regulation--prudence requirements and their reviewability.

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[2] Ad Hoc NARUC-EEI Committee, *New Approaches to Prudence Review: Gas Utility Construction at Major Generating Facilities* (June 6, 1991); Keystone Center, *Interim Report: Keystone Dialogue on State Regulation of Allowance Trading* (February 1992), 20-23; and Daniel J. Dudek and Joseph Goffman, "Regulatory Strategies to Stimulate the Allowance Market," mimeo (March 1992), presented at the 1992 NARUC Mid-Year Conference and EEI Conference on Allowance Trading, April 1992.

The Prudent Investment Test[3]

As part of the traditional regulatory compact, state commissions have provided utilities a reasonable opportunity to recover prudent investments and expenses. Prudent investments are allowed into rate base for capital recovery and are permitted to earn a return. Similarly, a utility is allowed to recover its prudent expenditures. The prudence test dates back to a concurring opinion of Supreme Court Justice Louis Brandeis in 1923. State commissions have developed four guidelines based on established case law in applying the prudence test. They 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, (3) there is a proscription *against* hindsight (no Monday-morning quarterbacking), and (4) there is a retrospective, factual review.

The presumption of prudence resulted in few prudence cases before 1973. The Brandeis guideline basically states that every investment and expenditure is presumed to be the result of reasonable judgment, unless the contrary is shown. State commissions have interpreted this as establishing a rebuttable presumption of prudence. Without affirmative evidence showing mismanagement, inefficiency, or bad faith, an investment decision is presumed to be prudent. The presumption of prudence makes for efficient regulation in that commissions are neither required nor allowed to review the prudence of all utility decisions regardless of their number, importance, or outcome. This saves commission resources by allowing staff and commissioners to concentrate oversight efforts on utility decisions the prudence of which are in doubt. While final results or outcomes of an investment or expenditure might overcome the presumption of prudence, they do not necessarily address the question of whether the investment or expenditure was reasonable at the time the decision was made.

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[3] Much of this subsection is drawn from Robert E. Burns et al., *The Prudent Investment Test in the 1980s* (Columbus, OH: The National Regulatory Research Institute, 1985).

Once the presumption of prudence has been rebutted, however, the utility has the burden of proving that the alleged imprudent investment decision was in fact prudent, and is held to a standard of reasonableness-under-the-circumstances that were known or reasonably knowable *at the time* of the decision. Although perfection is not required when the risk of harm to the ratepayer is greater than normal, the standard of care expected from a reasonable person is higher. In applying the standard of reasonableness-under-the-circumstances, which in some instances means highly risky and expensive projects, the utilities are held to a higher than normal standard of care to compensate for the risk and added expense associated with project decisions. State commissions have, understandably, sometimes held utilities to a high standard of care when applying the reasonableness-under-the-circumstances test to the completion of a nuclear power plant, for example.

The proscription against using hindsight is a corollary to the reasonableness-under-the-circumstances test. Decisions made by the utility are not subject to Monday-morning quarterbacking. Instead, they are to be judged in light of the conditions and circumstances that were known or should have been known *at the time* of the decision. The final outcome is not relevant.

However, the proscription against hindsight does not relieve a utility of its duty under the prudence standard to be vigilant to changing facts and circumstances. It is not enough to have made a decision that was "prudent" at the time it was made, if with due diligence the utility would have discovered that the facts and circumstances that the decision was based on had changed. Utilities are under a constant duty to be prudent and, when the stakes are sufficiently high, to check continually to see if the facts and circumstances have changed. Further, where there is a great deal of uncertainty as to the facts and circumstances at the time a decision is made, the most prudent approach may be for a utility to build flexibility into its planned actions; in this case its acid rain compliance plans.

This guideline against hindsight is familiar to members of the legal profession. In most litigation, the issue of liability focuses on the facts and circumstances at the time an expenditure or decision occurred, and not on the final outcome. This allows for a time-proven, "fair," and reasonably efficient assignment of risk between investors and ratepayers, with investors bearing the firm's "unsystematic" or "idiosyncratic" risks and ratepayers bearing "systematic" risks.

Unsystematic or idiosyncratic risk is related to the circumstances of a particular company, such as the risks associated with imprudent expenditures and decisions. Systematic risks are economy- or industry-wide, say, a prolonged or deep recession. The prudent investment test allows regulators to hold utility management responsible for unsystematic risks, while sheltering them (at least in part) from systematic risks beyond utility management control. Thus, commission use of the prudent investment test has held the utility accountable for risks that are particular to it (most of which are within the control of the utility management) and relatively harmless for most industry-wide risks outside of its control. This system of accountability seems sensible and consistent with the public interest. Many other systems of risk allocation and accountability, described later, might result in allocations that shift more risks to ratepayers.

The fourth guideline provides that once the presumption of prudence is overcome there be a retrospective, factual review to develop evidence about whether the investment decision was prudent at the time it was made. To do this, the evidence must be backward-looking. (No ongoing or periodic inquiry occurs because the presumption of prudence makes such an inquiry unnecessary.) The retrospective inquiry is factual; the commission is not seeking mere opinions. These facts should cover all the elements that did or could have entered into the decision, including all relevant information, decisionmaking tools, and the circumstances at the time. For example, it would be improper to use past data in a model to review a past decision if the model was not reasonably available in the past. The facts should also be aimed at helping the commission separate systematic from unsystematic or idiosyncratic risks.

Although one financial analyst[4] has labelled the prudence test a form of "predatory regulation," it cannot fairly be said that state regulators on the whole have

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[4] Charles M. Studness, "Excess Capacity and Imprudency," *Public Utilities Fortnightly* (March 15, 1991), 41-42.

abused or misused the test. A study by Oak Ridge National Laboratory set the total disallowance from 1980 to 1986 for nuclear power plant construction at $6.6 billion, of which $3.4 billion was disallowed as imprudent. The remainder was disallowed as not being "used and useful" or as being excess capacity. At the same time, a $70 billion capital investment was made in nuclear plants. Disallowances due to imprudence therefore represented only 4.8 percent of the capital expenditures eligible for rate base inclusion during this period.[5]

A later paper by Dr. John Anderson of the Electric Consumers Resource Council recounts that many utilities and their advocates claim that prudence disallowances have averaged 12 to 15 percent of construction costs. Dr. Anderson showed that the $9.8 billion in prudence disallowances between 1980 and 1988 amounted to 6 percent of *all* steam-electric plant entering operation ($156 billion) during that time.[6] Given the increased risks utilities faced in constructing nuclear power plants, this does not seem to be an unreasonable amount that utility stockholders were called upon to bear. It is likely, given the uncertainty (primarily of the systematic risk variety) concerning fuel price premiums and the price of emission allowances, that state commissions will not hold utilities to quite as strict a standard in compliance planning as in constructing nuclear power plants.

It is important here to distinguish between the prudent investment test and the used-and-useful test. Unlike the prudence test, the used-and-useful test does not require that a loss be due to an idiosyncratic risk for it to result in a disallowance. Disallowances can be the result of losses due to a systematic, industry-wide risk. It is worth noting that approximately half of the disallowances associated with nuclear power plants were of the used and useful variety. Those disallowances associated with plant

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[5] Oak Ridge National Laboratory, *Prudence Issues Affecting the U.S. Electric Industry* (Oak Ridge, TN: Oak Ridge National Laboratory, 1987).

[6] A Presentation by Dr. John A. Anderson at the 102nd Annual Convention and Regulatory Symposium of the National Association of Regulatory Utility Commissioners, Orlando, Florida, November 15, 1990.

cancellation were partial disallowances in most states. Although disallowances due to plant cancellations were never recovered, most state commissions recognized that plant cancellations were due to systematic risk, namely an unforecasted drop in demand. Since the cause of the cancellations was systematic, state commissions typically required only a partial disallowance. "Disallowances" due to overcapacity were typically temporary and plants were phased into rate base over a schedule or as they became needed. Often the utility was allowed to collect allowances for funds used during construction (AFUDC) while the plant was not in rate base so it experienced little or no losses.

It seems unlikely that a utility's actions taken to comply with the CAAA would not be considered used and useful. So long as a scrubber, fuel switching, or any alternative strategy has the desired result of lowering SO_2 emissions, the actions taken to fulfill the compliance plan will be held to be used and useful. Also, because of the relatively short timeframes involved, little danger exists that a compliance planning action once undertaken will be cancelled before it becomes "used and useful." (This is in contrast to the case of nuclear power plants which commonly took in excess of ten years to build, during which time the facts and circumstances that initially justified its construction could have changed leading to a prudent decision to cancel the plant--a prudent decision that nevertheless left the plant not used and useful. This highlights the prudence test as **the** relevant test for compliance planning.)[7]

As noted at the beginning of Chapter 5, § 403(f) of the CAAA specifically permits state commissions to engage in prudence reviews of utilities' allowance trading and compliance plans. If the prudent investment test were applied to compliance planning, one might expect state commissions to assume the utilities' compliance plan is the lowest-cost alternative. Given the uncertainties of the cost of premium low-sulfur fuels, the as-yet uncertain cost of advanced coal burning technologies, the marginal cost of

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[7] While the authors contend that prudence is **the** relevant test for compliance planning, it is possible to imagine some extreme scenarios where "used and useful" might come into play. For example, a scrubber could become too expensive to operate relative to its savings, or a plant may become too expensive to operate once it has a scrubber, or cheaper bulk power becomes available, or there is a significant demand reduction.

conservation and energy efficiency, the marginal cost of scrubbers, and the unknown and uncertain future value of emission allowances, the presumption of prudence could be challenged. Again, the standard of review is not one of perfection, but of making a reasonable decision given the facts and uncertainties that were part of the circumstances at the time. The process is similar to that faced by utilities preparing least-cost plans in states requiring them. Given the presumption of prudence and the consistent record of state commissions not applying hindsight in retrospective prudence reviews, utilities engaging in CAAA compliance planning have little to fear from the prospect of state commission scrutiny unfairly using the prudent investment test. The prudent investment test would only "punish" a utility for failing to consider all options in attempting to make reasonable efforts to seek a least costly strategy for compliance. One likely way a utility would be held imprudent would be to plan compliance on a stand-alone basis without considering the effect of selling or buying emission allowances.

Preapproval[8]

Alternatives to the prudent investment test have been suggested, most involving a preapproval process, whether of the utility's planned actions or its expenditures. Preapproving planned actions means a state commission reviews a utility's investment proposal and agrees to support those expenditures prudently and reasonably undertaken to complete the project. Indeed, preapproving planned actions would not differ greatly from certifications of convenience and necessity, preapproval of security issuances, or least-cost planning processes already in place at state commissions. The only difference is that preapproving planned actions would specifically find that the utility's planning is prudent. Legislative action that contains a form of preapproval of utility compliance

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[8] Much of this subsection is drawn from Russell J. Profozich et al., *Preapproval of Major Utility Investments* (Columbus, OH: The National Regulatory Research Institute, 1981); and Burns et al., *The Prudent Investment Test in the 1980s*.

decisions for the CAAA has passed in Indiana and is now being discussed in several other states.

In the context of a commission reviewing a utility's CAAA compliance plan, preapproving planned actions would involve the commission making certain that the utility examined all of the options and arrived at a least-cost plan.[9] Commission approval of the *plan* would guarantee support for reasonable and prudent expenditures made toward completing the compliance plan. The commission decision that the plan is prudent would be made contemporaneously when all of the uncertainties are still fresh in mind. There is little or no danger of hindsight from such a strategy. However, the state commission still may reserve the right to examine the reasonableness and prudence of *expenditures* toward the completion of the plan, and can require the utility to update periodically its compliance plan to reflect facts and circumstances as they change. This periodic updating might become part of the state's integrated or least-cost utility planning process.

A preapproval of *expenditures* refers to a state commission's approving the recovery of expenditures on a utility investment without the traditional retrospective, factual inquiry into whether the expenditures were prudent. Thus, a preapproval of expenditures could prove to be quite different from current commission practices. Preapproval of expenditures would seem unlikely to be implemented by a state commission, unless it were accompanied by a contemporaneous assessment of the prudence and reasonableness of the utility's expenditures by the commission or its staff. Such a close involvement by the commission or its staff might result either in the commission becoming "coopted" by the utilities or with the commission staff taking over the utility's management tasks. Neither is thought to be desirable. Moreover, most

[9] Given the uncertainties involved in this type of prospective decisionmaking, the use of innovative administrative procedures--such as joint problem solving or the collaborative process--might be appropriate. See Robert E. Burns, *Administrative Procedures for Proactive Regulation* (Columbus, OH: The National Regulatory Research Institute, 1988).

commissions do not currently have the resources to commit to a detailed analysis of utility compliance expenditures that would seem to be required for preapproval.

As noted earlier, there are four significant problems associated with the preapproval procedure. The first is its potential financial impact that stems principally from its potential for both risk reduction and the shifting of risk from stockholders to ratepayers. This could be the case because not all of the uncertainties associated with compliance planning decisions can be reduced or eliminated; the remaining risks are shifted from shareholders to ratepayers. To see this, consider that there are basically several types of risk that the utility faces: market risk associated with changing supply and demand conditions (for example, fuel price changes or changes in the demand for electricity), technological risk associated with changes in technology (for example, equipment obsolescence), and regulatory risk, which results from unexpected changes in regulatory treatment or some future action by the commission.

Utility managers and investors are compensated for bearing the first two, technological and demand, risks in their rate of return, ***to the extent they are within the utility's control.*** Regulatory risk most would agree can and should be reduced. While regulatory risk potentially can be reduced by preapproval, preapproval in no way reduces technological and demand risks; it merely shifts these risks from utility stockholders to ratepayers. That is to say, those who bear the risks are not compensated for doing so.[10] To avoid the socialization of risks (and losses) accompanied by the privatization of undue profits, any decrease in risk bearing on the part of the utility should be reflected by a decrease in the equity portion of the utility's rate of return.

Moreover, the concept of preapproval may be inconsistent with most current regulatory practices. Most states regulate their jurisdictional investor-owned utilities with rate-base/rate-of-return or cost-based regulation. A major and often cited disadvantage to cost-based regulation is that the utility has little or no incentive to minimize its cost where the firm's return on investment is not based on its performance. Retrospective

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[10] In other words, there may be deterioration in the efficiency with which society bears risks.

reviews of utility actions evolved to counteract this lack of incentive (among other things). Removing the possibility of retrospective reviews with preapproval only serves to remove this rectification of cost-based regulation. Therefore, lowering the rate of return with preapproval does not, in itself, insure cost minimizing behavior by the utility.[11]

Steps can be and probably should be taken to reduce regulatory risk. One way is to make future regulatory actions more predictable. While there have been several proposals for preapproving compliance plans, expenditures, or both, a reasonable degree of predictability is all that is required to enable a utility to anticipate commission actions. These actions then can be considered by the utility when examining the various compliance options it faces.

It is appropriate for utilities to ask for and expect clear and relevant guidelines from their state public utility commissions on ratemaking treatment of allowances and compliance expenditures, and also the standard to be used for any future reviews of compliance planning decisions. As noted above, regulators might apply a prudence standard as the appropriate way to balance ratepayer and stockholder risks by having the ratepayers bear systematic risks, those beyond the control of the utility, while shareholders bear the unsystematic or idiosyncratic risks that are within the control of the utility.[12] If a prudence standard is applied, it is important that it be applied in a manner consistent with the way it was originally envisioned, a retrospective factual review of the utility's reasonableness given the facts and circumstances at that time, **without hindsight**. Without this standard, the cost of a retrospective review could be as much or more than the cost of a preapproval process. The possibility of a retrospective review has the important feature that it gives the utility a strong incentive to control its costs.

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[11] For a discussion of incentive-based regulatory methods see Kenneth Costello and Sung-Bong Cho, *A Review of FERC's Technical Reports on Incentive Regulation* (Columbus, OH: The National Regulatory Research Institute, May 1991).

[12] If the used and useful test did come into play, then some or all of the systematic risks are borne by the utility. See Burns et al., *The Prudent Investment Test*.

Critics of the traditional prudence test are exploring another option sometimes called a "rolling prudence review."[13] Such a review involves preapproving the utility's planned actions and making a contemporaneous, periodic approval of the prudence of the utility's expenditures. The technique is closely akin to the preapproval of expenditures just described. The only major difference is the periodic, contemporaneous prudence reviews of expenditures--perhaps at significant construction milestones. For a state commission to engage successfully in a rolling prudence review, it would seem to need an independent, highly experienced engineering staff member on site to oversee utility construction expenditures as well as other financial experts qualified to judge the prudence of expenditures on a contemporaneous basis.

Even so, the lack of retrospection could create problems. Without some retrospection, a commission probably could not separate systematic from unsystematic risks. Also, there might be the problem of "hidden imprudence," an example of which, in another context, was bad welds in a nuclear power plant that went undiscovered until the plant was close to completion. Because of the seriousness of the hidden imprudence in that particular case, the plant was converted from nuclear to coal at considerable additional expense.[14]

This leads to the second problem associated with preapproval, it requires considerable resources, expertise, and involvement by the commission. Prudence, on the other hand, when applied correctly, requires fewer resources because of the "presumption of prudence." Some state public service commissions, particularly those experiencing severe budget reductions, may find it difficult to devote the resources required to examine in detail a utility's plan. Moreover, utilities will always know their system and their options better than anyone else. This underscores again the need for a regulatory treatment of allowances that minimizes the state public utility commission's involvement and is, as much as reasonably possible, self-enforcing.

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[13] See footnote 2, this chapter, *supra*.

[14] The cost associated with the Zimmer plant is currently under review by The Ohio Public Utilities Commission.

The third problem with preapproval is that it is likely to lock the utility into its commission-approved plan of action. Once a utility has successfully negotiated a plan with the state public service commission and other parties, a task which will likely involve considerable time and effort, it is unlikely to seek changes to the specifics of the plan. Any deviation from the agreed-on plan is likely to reopen negotiations. As often has been seen in the past, changes in the price and availability of fuels can occur quickly and necessitate a change in an approved plan. Allowance price changes are likely also to necessitate changes in the plan, such as buying and selling arrangements. Depending on the particular features of the agreed plan, preapproval could also encourage large capital expenditures and a "go it alone" strategy, that is, if the plan does not require allowance purchases.

The fourth problem is that once the commission approves a plan of action, particularly if expenditures are guaranteed to be recoverable from ratepayers with no or limited retrospective review, then the utility is likely to become less vigilant in carrying out the plan. This again points to the possible need for a retrospective review. Preapproval does not increase the chance of fraud, since state public service commission can always take action when fraud is demonstrated. However, outright fraud by a utility is extremely rare. The problem is that under a preapproval scheme, a utility has less incentive to minimize cost and pursue ways to reduce cost beyond what is specified in the compliance plan, once the plan is preapproved by the state public service commission. Further, it is more difficult for a state public utility commission to expose things that the utility could have done (errors of omission) in contrast to things the utility actually did under a preapproval scheme than one using a retrospective review, because the utility has more complete first-hand information on its options than the commission.

Acknowledging that it is desirable for state public service commissions to take action to decrease regulatory risks, an alternative method is for a commission to issue clear guidelines stating the rules of the game "up front" for CAAA compliance. A specific statement, in as much detail as possible, outlining the commission's regulatory approach would tend to reduce regulatory risks to the utilities by making regulatory action *more predictable* but without the downside of shifting to ratepayers technological and demand risks that might be associated with a preapproval process.

PART III

REGULATORY POLICY ISSUES

CHAPTER 7

REGULATORY INCENTIVES AND THE ECONOMICS OF ALLOWANCE TRADING

This chapter develops an economic model of allowance trading when the output market of affected firms is subject to public utility regulation. Rather than placing a firm's productive enterprise in the background to highlight the effects of environmental policy, the productive and environmental decisions of the firm are placed at the center of the model.

This work will not attempt to advance the treatment of rate-of-return regulation, and so it begins with the venerable formulation of Averch and Johnson.[1] In turn, the model is augmented with command-and-control (CAC) and market-based environmental constraints. In each instance we seek to deduce the effects of environmental and rate-of-return regulation, and in particular the *joint* effects of the regulatory treatment of allowances and the environmental constraint upon utility decisions.

The CAC case is analyzed for purposes of comparison between the current (pre-1995) environmental law governing utility behavior and the CAAA. A rate-of-return-regulated firm will respond in some predictable ways to the rate base treatment of scrubber capital. In particular, if scrubbers are placed in the rate base (as they are in forty-nine states) then revenue requirements rise and with them electricity prices. This suggests that current regulatory practice is probably not optimal from the viewpoint of consumers, though utilities certainly benefit. Whether the inclusion of scrubbers makes society better off or not is an open question, but early results from some related research suggests that society does indeed benefit.

In the presence of emission allowances, under the assumption that scrubbers are included in the rate base, the question of whether emission allowances themselves should be rate base assets is then taken up. It is found that from the viewpoint of consumers,

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[1] Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* 52 (1962): 1052-69.

allowances should not be included in the rate base. Including them unquestionably is good for utilities, and it may be that their inclusion is good for society as a whole. Consumers, however, will benefit if allowances are not included in rate base. This is not a final answer, however, to the question of how compliance capital should be treated. If the two decisions--whether to include scrubbers and whether to include allowances in rate base--are made simultaneously, then the optimal regulatory treatment may look different. Two strong tensions that commissions feel are examined in the remainder of this chapter: (1) they must balance the interests of consumers against the interests of society as a whole (which benefits from a stable, healthy utility industry) and (2) they should, in the interest of minimizing the cost of environmental protection in the manner laid out in the CAAA, seek to foster the allowance market by encouraging its use.

The mathematical development that supports the arguments of the chapter appears in Appendix D. In some instances the prescriptions of the formal model are somewhat tentative. However, there are some recommendations that appear to follow from a reasonable set of assumptions.

Two themes unify the chapter. First, the theoretical results on the efficiency properties of allowance trading schemes in the absence of market imperfections are taken as given (as outlined in Chapter 3). If nothing went wrong, market-based environmental control would be a good form of public policy. In fact, of course, things do go wrong, and this constitutes the second theme: the way that the decisions of the two regulatory bodies--federal and state environmental regulators and economic regulators (commissions)--interact with one another and affect the compliance decisions of utilities.

A series of results is derived that points out the inherent paradox that commissions face in deciding how to treat allowances for ratemaking purposes. On the one hand, a smoothly functioning active allowance market is needed to minimize the cost of complying with the CAAA. The advantages of market-based environmental regulation may be lost if this allowance market does not develop. However, fostering the market by making allowances an attractive compliance strategy requires that allowances be treated in a manner similar to abatement capital, which can result in higher prices for ratepayers.

A brief overview of the regulatory literature is also provided. The next section develops the model and explores the joint effect upon an electric utility of a simple CAC environmental constraint in the presence of ROR regulation. The subsequent section investigates the firm's response to an allowance market without ROR regulation, then adds an ROR constraint, investigating how this sort of regulatory regime further affects a firm that faces environmental regulation. Some concluding comments and thoughts about further extensions of this work appear in the last section.

The central question of this chapter is what happens when the two themes of environmental and economic regulation are joined. As each has a separate and extensive literature, it is helpful to review them briefly. The development of tradable pollution rights research was described in Chapter 3, with an emphasis on those ideas that bear upon the clean air legislation. This chapter next summarizes the utility regulation literature, which once again focuses on those ideas of primary importance for this study.

The Economics of Public Utility Regulation

There exist many thorough accounts of the rationale for, and the objectives and methods of regulating, public utilities and other businesses.[2] A "natural monopoly"--that is, a firm whose marginal costs are everywhere lower than average costs--supplies its product at a lower cost than any two or more smaller firms could do. In this case, a single firm or a few firms may be allowed to exist, protected in some fashion from new entrants and other competitive forces, but required to submit to government control over some portion of their operations.

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[2] Alfred Kahn's two-volume *The Economics of Regulation: Principles and Institutions* (Cambridge, MA: MIT Press, 1988), is a classic source. A more recent volume that addresses certain concerns that are of current interest is J. J. Hillman and R. R. Braeutigam, *Price Level Regulation for Diversified Public Utilities* (Norwell, MA: Kluwer Academic Press, 1989).

The theory of economic regulation supposes that the regulator's behavior is guided by the interests of the consuming public, and also, in some cases, the national security. Regulator might regulate the return that owners of a regulated firm are allowed to earn on their investment. Even when the principal driving regulatory policy is rate-of-return regulation, the regulation itself is likely to take the form of a price level or rate structure for electricity, natural gas, or telephone services.

It is not our purpose here to add to the extensive writings on the pure economic theory of regulation, nor even to provide anything like a comprehensive survey of that literature. However, the regulation of industries is informed by certain economic principles, which shall be summarized briefly. The rate-of-return approach to regulation has been a prominent feature of regulatory practice for several decades. In recent years, the disadvantages of ROR regulation have spurred scholars and practitioners to seek alternative regimes.

Rate-of-return regulation consists of placing a limit on the rate of return that a regulated firm may earn on its capital investment. This constraint, if effective, cannot be helpful to the firm, whose optimal operating decision would not be improved by a new restriction on what it can do. The purpose of such a policy is to ensure that the firm cannot exploit fully its monopoly power at the expense of consumers. In practice, the regulator most often sets a price or a set of prices that the firm must charge for its product. This rate structure is devised so that the resulting return on the firm's capital matches the regulated rate. At various intervals, the rate structure might be revised to maintain the rate of return at its proper level while input prices, demand levels, productive capacity, or a host of other conditions change over time. Typically, the regulator uses some measure of the actual book value of the utility's invested capital. The allowed rate of return is applied to this rate base. Naturally, the choice of rate base is critical for the firm's overall profitability, so the selection of a rate base measure also is extremely important.[3]

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[3] Bruce C. Greenwald, "Rate Base Selection and the Structure of Regulation," *Rand Journal of Economics* 15 (1984): 85-95.

In a landmark article, Averch and Johnson[4] argued that if the firm is allowed to earn a rate of return that exceeds its cost of capital, then the regulated firm will have an incentive to overinvest in capital. This rate base inflation leads to a corresponding increase in the total returns that the firm may earn while still satisfying the constraint. The overcapitalization result they described has become known as the "A-J effect." Whether the effect exists has been the subject of a good deal of empirical research.[5]

Spann[6] and Petersen[7] find a significant degree of overcapitalization, while Baron and Taggart[8] find the opposite. Whether the A-J effect is an empirical reality or not, indications are that ROR regulation provides a regulated firm with the incentive to behave inefficiently. For example, diversification into industries unrelated to the regulated industry might let the firm cross-subsidize and increase its profitability. This is true so long as the capital required for new ventures is counted as part of the rate base or the cost can be passed on to its regulated customers. Another example is the propensity of regulated firms, prior to the mid-1970s, to substitute capital for fuel.

The Averch and Johnson model is static in nature, meaning it cannot account for any dynamic rate adjustment mechanisms, prudence reviews, or other matters that unfold

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4 Averch and Johnson, "Behavior of the Firm Under Regulatory Constraint."

5 For a survey of this literature, see Paul L. Joskow and Nancy L. Rose, "The Effects of Economic Regulation," in R. Schmalensee and R. D. Willig, eds., *Handbook of Industrial Organization, Volume II* (Amsterdam: Elsevier Science Publishers, 1989).

6 Robert M. Spann, "Rate of Return Regulation and Efficiency in Production: An Empirical Test of the Averch-Johnson Thesis," *Bell Journal of Economics and Management Science* 5 (1974): 38-52.

7 H. C. Peterson, "An Empirical Test of Regulatory Effects," *Bell Journal of Economics and Management Science* 6 (1975): 111-26.

8 David P. Baron and Robert A. Taggart, "A Model of Regulation Under Uncertainty and a Test of Regulatory Bias," *Bell Journal of Economics* 8 (1977): 151-67.

over time. This feature was criticized by Joskow,[9] who argued that in an inflationary period the rate of return on capital will tend to fall below capital costs, an outcome the A-J model cannot accommodate.

Baumol and Klevorick[10] present Averch and Johnson's results in a more rigorous manner, clarifying some of its assumptions and interpreting the answers more carefully. Baumol and Klevorick show, for example, that it cannot be concluded from Averch and Johnson that the capital-fuel ratio of the regulated firm will be larger than that of a corresponding unregulated firm. Rather, all that can be said is that the capital-fuel ratio will be larger for a regulated firm than if the firm were minimizing costs and producing the same level of output. This point is important, for it emphasizes one of the problems that ROR regulation presents for industry and regulatory agencies alike: firms may not have an incentive to select input levels efficiently. Baron provides a model in which the firm and the regulator satisfy an incentive compatibility requirement and in which an equilibrium outcome coincides with the Averch and Johnson overcapitalization result.[11] The important point from Baron's discussion is that in a situation such as the one under investigation here, the A-J outcome occurs.

Rate-of-return regulation has often been criticized for not responding well to dynamic changes in the regulatory environment. The incentive that this gives firms to

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[9] Paul L. Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation," *Journal of Law and Economics* 17 (1974): 291-327.

[10] William J. Baumol and Alvin K. Klevorick, "Input Choices and Rate-of-Return Regulation: An Overview of the Discussion," *Bell Journal of Economics and Management Sciences* 1 (1970): 162-90.

[11] David P. Baron, "Design of Regulatory Mechanisms and Institutions," in R. Schmalensee and R. D. Willig, eds., *Handbook of Industrial Organization, Volume II* (Amsterdam: Elsevier Science Publishers, 1989). A regulatory regime is incentive compatible if the regulator and the firm gain nothing by withholding information from one another. The firm, for example, will not misrepresent its costs.

produce in an inefficient manner[12] has prompted the search for alternative regulatory schemes that remove or at least alleviate such a problem. One leading alternative is price cap regulation.[13] This new approach has a number of potential benefits over ROR regulation. In the pure form of price cap regulation, once the price cap is set the firm has no or little incentive to choose an inefficient input mix, to underproduce, to undercut its competitors in its unregulated markets, or to behave inefficiently when choosing its production technologies. In short, the firm is provided with more incentive to minimize its cost. Also, since the regulator is focused on the firm's prices rather than costs, there is no incentive to misreport costs. Baron[14] and Hillman and Braeutigam[15] offer thorough surveys of the literature on incentive-based regulation. Lawton and Rose[16] discuss some of the practical issues that arise in implementing price cap regulation.

This sketch of the theory of regulation provides a backdrop for the model developed in the following section. Once again, the objective of this chapter is to combine a model of regulatory constraint with an environmental constraint, and to use

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[12] For a discussion of these limitations of ROR see Chapter 8 of S. V. Berg and J. Tschirhart, *Natural Monopoly Regulation: Principles and Practice* (Cambridge, U.K.: Cambridge University Press, 1988). For an opposing view see Douglas N. Jones, "What's Right With Utility Regulation," *Public Utilities Fortnightly* (March 6, 1986).

[13] See R. R. Braeutigam and J. C. Panzar, "Diversification Incentives Under 'Price-Based' and 'Cost-Based' Regulation," *Rand Journal of Economics* 20 (1989): 373-91; Hillman and Braeutigam, *Price Level Regulation for Diversified Public Utilities*; Paul L. Joskow and Richard Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation* 4 (1986): 1-49; T. R. Lewis and David E. M. Sappington, "Regulatory Options and Price-Cap Regulation," *Rand Journal of Economics* 20 (1989): 405-16; and David Besanko and David E. M. Sappington, *Designing Regulatory Policy with Limited Information* (New York: Harwood Academic Publishers, 1987) for a variety of views upon price cap and incentive-based regulatory regimes.

[14] Baron, "Design of Regulatory Mechanisms and Institutions."

[15] Hillman and Braeutigam, *Price Level Regulation for Diversified Public Utilities.*

[16] Raymond W. Lawton and Kenneth Rose, eds., *Regulatory Perspectives on Price Caps* (Columbus, OH: The National Regulatory Research Institute, 1992).

the model to examine the effect of different commission policies on utility decisionmaking.

A Model of ROR Regulation with a CAC Environmental Constraint

Much has been said about rate-of-return regulation and market-based environmental regulation when only one of these two regimes is present. How do firms respond when they simultaneously must satisfy both environmental and economic controls? The analysis conducted here provides a framework to examine how regulatory treatment of compliance strategies affects utility decisionmaking. Even the simplest version of a model with both economic and environmental regulation is fairly complicated. Before proceeding to a version with allowance trading, an intermediate case will be presented. Here, the utility still must satisfy an ROR constraint, but also faces a command-and-control environmental constraint. In the following two sections things become more complicated: an allowance market is added to the firm's choice of compliance strategies.

The starting point here is a variant of the model of firm behavior under rate-of-return regulation due to Averch and Johnson. This model supposes that a monopoly firm is producing some output, which will be called q, using a pair of inputs, x and k_1. This firm is not a natural monopolist but derives its monopoly power from its status as the only seller of q. Suppose that x denotes some variable input such as fuel, and that k_1 denotes capital input. The firm's profits are subject to a regulatory constraint that prevents the firm from earning a rate of return on its capital investment greater than some amount s, where the cost of capital equals r, and where $s > r$. The cost of x, the noncapital input, is recovered at exactly its acquisition cost.

The model's primary components are (1) the demand for electricity (denoted $p(q)$), (2) the prices of the inputs (denoted w and r for fuel and capital respectively), (3) the relationship between inputs and output (represented mathematically by a *production function* $q = f(x,k_1)$), and (4) the allowed rate of return s. By its choice of input levels, the firm automatically selects q (and thereby selects the price p) and the cost of purchasing inputs. Thus, the firm's only real decision is a pair of input levels. Its profits (revenues less costs) are completely determined once x and k_1 are chosen.

As is well known, if the A-J model governs firm behavior and if $s > r$, the firm will "overcapitalize": its choice of inputs will not necessarily minimize the cost of producing a given level of output. The same firm, in the absence of an ROR constraint, will always choose input levels so that the marginal rate of technical substitution between them equals the ratio of their prices. This is the usual cost-minimizing input choice. This result does not hold in the presence of an ROR constraint, however. Instead, the firm overinvests in capital. For any given level of electricity production, the theory says, the utility will use more capital and less fuel than if it were minimizing cost. Though not all utilities overuse capital, it is not difficult to find instances in utility industries where firms appear to have overinvested in capital.[17]

The Averch-Johnson story--and the debate surrounding it--shall be left here, and the effect of environmental regulation on the behavior of a firm in the presence of a ROR constraint taken up. Imagine now that the utility's emissions of some pollutant (say, sulfur dioxide) are constrained. For an electric utility, it is natural to think of the "pollutant of interest" as sulfur dioxide; that language will be used here. It will be assumed that the limit on emissions may be reached only by reducing output or by installing abatement capital (such as scrubbing equipment). Suppose that the firm may purchase this abatement capital, denoted k_2, at the price r per unit, and that its emissions depend upon output q and the amount of abatement capital the firm installs. The emission level e depends only upon the level of generation q and the level of k_2. Let emissions be represented by the mathematical expression $e = h(q,k_2)$. If everything else is held constant, sulfur emissions rise with increases in output q; they decrease with increases in abatement capital.

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[17] *Are the Electric Utilities Gold Plated? A Perspective on Electric Utility Reliability*, Congressional Research Service, Library of Congress (April 1979).

Finally, since this is command-and-control environmental regulation, we need a name for the upper limit on the firm's emissions. Let this quantity be called E_0; the environmental restriction says that $h(q,k_2) \leq E_0$. The utility still has a good deal of latitude in its production decisions. It may choose any combination of output and abatement capital that it wishes, so long as emissions stay below the cap and the utility fulfills its obligation to serve. The primary difference now is that any increase in electricity generation (which always means a higher level of sulfur emissions) must be accompanied by the purchase of a little bit more abatement equipment.

Once again, it is assumed that k_1 is in the rate base. At issue now is the decision of the regulator whether or not to allow k_2 in the rate base. The answer to this question in either a normative or a positive sense is not obvious. How do the firm's decisions about pricing, production levels, sulfur emissions, and so on depend upon the regulatory treatment of abatement equipment purchases? This question is the primary question of the chapter.

The symbol φ will be used to denote the *share* of k_2 placed in the rate base. If $\varphi = 1$, then the utility is allowed to claim all of its abatement capital. If $\varphi = 0$, none of k_2 is in the rate base. Of course, for values of φ between 0 and 1, some intermediate portion is in the rate base, which is now equal to $k_1 + \varphi k_2$.

Including the environmental constraint changes both the utility's profits and its ROR constraint. Costs formerly amounted to purchases of fuel and capital, equalling $wx + rk_1$. They now also include the cost of abatement capital, so that costs (assuming variable costs are unchanged) equal $wx + r(k_1 + k_2)$. The ROR constraint in the simple A-J model says that profits cannot exceed $(s - r)k_1$. Here, the utility is allowed to earn the rate s on at least a share of its abatement capital. If $\varphi = 1$, for instance, then the constraint becomes $(s - r)(k_1 + k_2)$.

In the absence of an environmental constraint, the utility facing ROR regulation balances the costs (due to purchase requirements) and benefits (due to increased rate base and the corresponding increase in profit opportunities) of owning capital. (In

Appendix D, the corresponding derivation for a utility facing both ROR and environmental constraints is presented.)

It is assumed here that the utility is free to choose the price at which it sells electricity and also the amount of electricity that it produces. How does this make sense when in practice ROR regulation amounts to a regulated price? Because the utility has some monopoly power. It faces a downward-sloping (and somewhat elastic) demand curve and the demand curve for electricity is well-defined. Therefore, it makes no difference whether the regulator dictates a price or a rate of return. In either case, the firm will use the demand curve to calculate the optimal amount of electricity to generate, and will satisfy the regulatory constraint while maximizing profits and meeting its obligation to serve.

Ultimately, the issue is in what direction would the firm's output move in response to a change in φ? To find the answer, think about the way a monopoly producer views additional output. Unlike a competitive firm (whose output is always valued at the prevailing price), an unregulated monopolist by *increasing* its output causes the price of its product to *fall*. To sell the additional product, it must now charge a lower price for all of its production. This fact makes life complicated (and profitable) for a monopolist. Of course, when the monopolist restricts production to achieve a higher price, consumers suffer because they buy less of the good and pay a higher unit price for it. This fact, and the perceived need to protect consumers from exploitation at the hands of a naturally monopolistic seller like an electric utility, underlie the logical justification for public utility regulation.

The fact that a utility usually wishes to reduce output has important consequences for the regulatory treatment of abatement capital. A regulated utility will usually respond to a decision by the regulator that permits profits to increase by reducing its output level. A monopolist's natural tendency is generally to reduce its output level. Now consider the case of the utility and suppose that φ is fixed at some level less than one. Take, for example, the case with $\varphi = 1/2$, in which case the rate base has value $k_1 + 0.5k_2$. Both the ROR constraint and the emissions constraint are binding. Now suppose that the commission decides to increase φ slightly. What will be the utility's response?

If the utility were to continue operating as before using the same input mix and producing the same level of output, the ROR constraint suddenly would be nonbinding. Profits would be lower than their allowed level. To take up the slack in this constraint and to increase profits to the maximum allowable level, the utility will *decrease* its output level.[18]

This sets in motion a series of events that leads to a situation in which electricity production has unequivocally fallen, the price of electricity has risen, the utility's emission level has remained unchanged, and the use of capital inputs--k_1, and k_2--has been reduced.

The intuition for this result relies on the fact that the firm can substitute k_1 for k_2 in its profit constraint.[19] These two inputs both appear in the constraint, and depending on the size of phi are more or less substitutable.

Figure 7-1 illustrates the logic of the argument that connects q and k_2. In the diagram, k_2 and q appear on the axes, and the curve labelled E_0 denotes the set of (k_2,q) pairs at which emissions equal exactly E_0. Given the CAC regime, the firm will always operate along this curve. Any time it reduces its output level q, say from q_0 to q_1, to stay on E_0-curve it must also use a bit less k_2, from k_2^0 to k_2^1g.

Cutting back on output to exploit the more liberal profit constraint, the utility will use less of k_1. When it reduces q, it also reduces emissions, so that the CAC emissions constraint E_0 is no longer binding. Though it will lead to a slight reduction in the size of the rate base, the firm's response is to reduce slightly its use of abatement capital k_2. At the new optimal plan, with φ now greater than 0.5, the firm's use of k_1 and k_2 will have

[18] There is a set of mathematical conditions that must be satisfied by the firm for this statement to be correct. These conditions are spelled out in Appendix D, and they are sufficiently mild that they will often be met.

[19] It is only in the profit constraint that k_1 and k_2 can be substituted for each other. They are distinct as inputs to abatement and production.

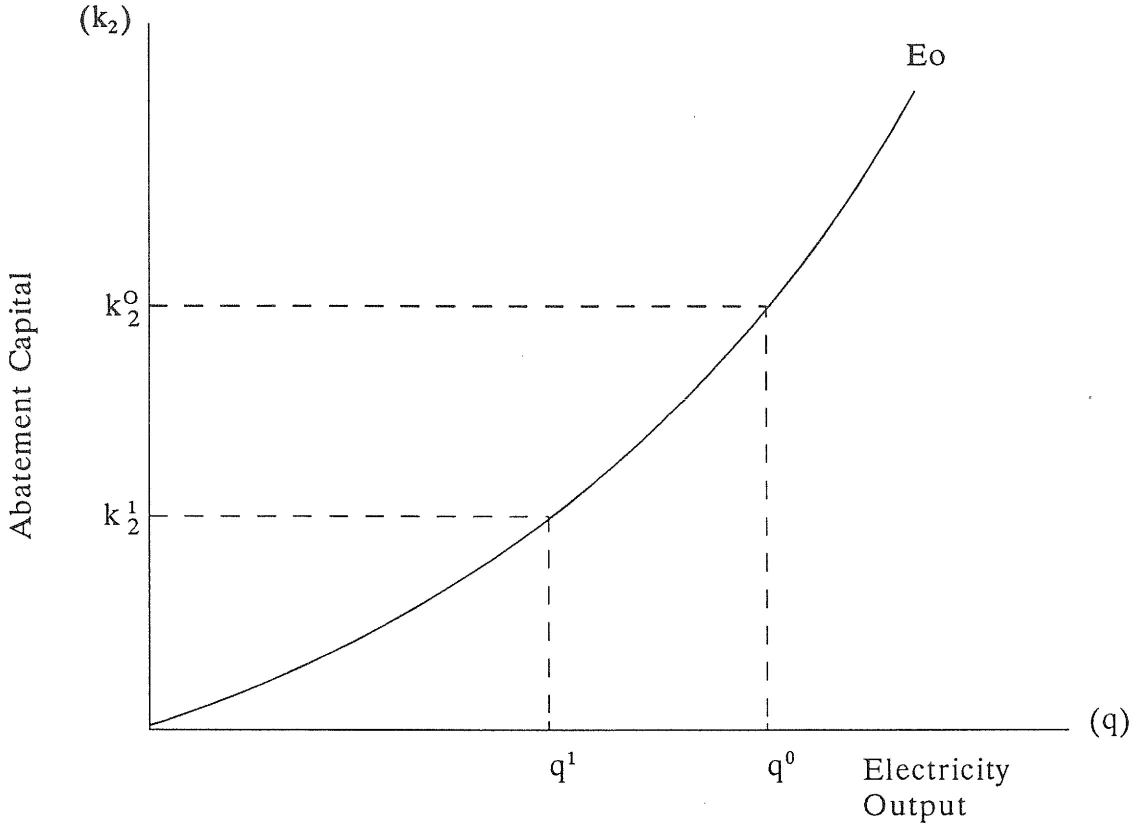

Fig. 7-1. Change in k_2 in response to a change in q.

fallen, as will its output level q. But if q falls then the price that consumers must pay for electricity will rise as we move upward along the demand curve. These two changes--reduced electricity use and increased price--both work against consumers. As the share of abatement capital allowed in the rate base increases, consumers are made worse off.

What must be noted is the fact that with the exception of Tennessee (which regulates no electric generating units), pollution abatement equipment is allowed to be placed in the rate base by every state commission and the FERC.[20] Plausible arguments justifying this policy are not difficult to come by. If society wishes to have clean air, one argument goes, it should expect to pay for it. The result of placing abatement capital in the rate base must be faced, however. This policy by commissions has significant equity consequences, and the financial losers are electricity users.

Though the consumers of electricity prefer to see scrubbers left out of the rate base, utilities and their shareholders prefer to have them included. Whether the inclusion observed in forty-nine states is optimal from society's viewpoint--that is, whether the gain felt by shareholders exceeds the cost to ratepayer--is an unanswered question. Still, the single most important finding from this model with CAC environmental regulation is that electricity prices always rise when abatement capital is included in the rate base. If $\varphi > 0$ (so that at least a part of abatement capital is included), then reducing φ always increases the amount of electricity produced and leads to lower electricity prices. Both of these add to consumer welfare.

As we will see, things become a good deal more complicated when environmental regulation includes market-based allowance trading. This investigation is the focus of the next section. There, the competing interests of reducing the cost of complying with the CAAA (by encouraging allowance trading) and increasing consumer surplus (by leaving things out of the rate base) must be dealt with. Given that in practice $\varphi = 1$, a decision to rate base allowances may help in the former (by encouraging the trading of allowances) but hurt in the latter (by further increasing profit opportunities for utilities, which then reduce output further). Commissions should seek to equalize the incentive structure across compliance strategies, but that this may worsen the unpalatable features of the status quo regulatory policy.

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[20] National Association of Regulatory Utility Commissioners, *1989 Annual Report on Utility and Carrier Regulation* (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1990).

Emission Allowance Trading without ROR Regulation

When a utility faces a command-and-control environmental constraint, its problem is both more difficult and simpler than if it were able to trade emission allowances. It is made more difficult because the constraint on pollution is more firm--there is less flexibility permitted in compliance planning when allowance trading is not an option. But the decisionmaking process itself is simpler because one complicating factor may be safely ignored since the firm is simply told how much it can pollute. If the allowance price is known, the utility makes its decision about how much to pollute based only upon its own situation. This freedom to choose any amount of emissions makes the decision more complicated. To reduce the degree of complexity somewhat, the firm's decision first will be explored without the complication added by an ROR constraint. The next section presents the results of putting the two regulatory constraints together.

Suppose, as before, that the firm uses x and k_1 in producing electricity, and that it emits pollution in an amount depending on q and the level of k_2. There is no ROR constraint so there is no concern over whether abatement capital is in the rate base. Gone as well is the pollution limit E_0 that appeared in the previous section. It is replaced with an allowance requirement that works as follows.

An *emission allowance* is a license to emit one unit of SO_2. The firm may choose to emit any level of pollution it wishes, so long as it holds allowances in at least that amount. Let ℓ denote allowances or licenses held by the firm, and suppose that the firm is given an endowment of licenses L_0. These licenses may be bought and sold in any amount at the price p_ℓ. What does this firm's profit function include? The firm still earns revenue from the sale of electricity (and potentially from the sale of allowances), and its costs are incurred through the purchase of fuel, the two kinds of capital (k_1 and k_2), and the purchase of allowances. Because we are not considering the dynamic nature of the problem, there is no incentive for the firm to store allowances for future use. This means the firm will always use exactly as many allowances as it holds; all extras will be sold at the prevailing allowance price.[21] Profits are described by $p(q)q$ - wx - $r(k_1 + k_2)$ - $p_\ell(h(q,k_2) - L_0)$. Note that if the firm chooses to use less than its endowment of allowances, $p_\ell(h(q,k_2) - L_0)$--which then would be negative--is an addition to profits.

Keep in mind how the decisions that the utility makes are implemented and how they affect profits. The choice of how much of the productive inputs x and k_1 to use determines the level of electricity production, q. Together k_2 and q determine the level of sulfur emissions the utility puts out, which in turn determines how many licenses it must hold. Of course, all these things must be selected simultaneously, but it is important to keep in mind just how the various choices feed upon one another. When rates of return are also regulated, things get more complicated.

The reader may consult Appendix D for an account of the mathematical problem that a firm seeks to solve. Of primary interest here is the expression that describes the incentives the firm responds to when choosing compliance strategies and emission levels in the absence of ROR regulation. Keep in mind how this fits into the larger picture. Economists have advocated allowance trading based upon the recommendations of their theoretical models, which have almost always been free of utility regulation. Here, the simple allowance trading model without ROR regulation gives us the clearest idea that this model can give about the firm's decisions when offered the chance to enter an allowance market for environmental regulation. In other words, this version is the benchmark against which things will be compared in the following section.

Equation (D-10) in Appendix D shows how the firm will balance the costs of two compliance strategies available to it: buying abatement capital and buying allowances. It shows that in the absence of ROR regulation, the firm behaves to equalize the marginal cost of purchasing allowances and buying abatement capital. The equation tells us that the firm should equate the marginal costs of using allowances and of purchasing abatement capital. Thus, we see that this mathematical result is in accord with the usual economic recommendation: a firm that is free of regulatory intervention will set the

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[21] This means that $\ell = h(q,k_2)$ will always hold. See Appendix D for a discussion of the technical consequences.

marginal cost of the various compliance inputs equal to one another and equal to their marginal benefits.

In the next section a more complicated treatment of the allowance market behavior of a utility is presented. There, the firm must worry both about the purchase of allowances and abatement capital and about the effect upon these purchases of the rate-of-return constraint. We will see that when the joint influences of environmental and economic regulation are allowed full play even in a simple model such as this one, things get very complicated. However, there are also some intuitively appealing recommendations that result from the mathematical work. These seem to agree with conventional wisdom about the role of market forces in the regulation of the environment.

Emission Allowance Trading with ROR Regulation

In an earlier section, the utility faced both environmental and ROR regulation, but was limited in the ways it could satisfy the environmental constraint. In the previous section, the decision of how to meet the environmental constraint was more complicated, but the utility was not further confined by economic regulation. Here all of the complications are in place: the utility faces a limit on the rate of return it may earn on its capital stock, it must decide how much sulfur dioxide to emit, and at the same time it must decide how much abatement capital to purchase.

Earlier we saw that whether or not abatement capital was allowed in the rate base helped to determine the firm's production and emissions decisions. The conclusion was that consumer welfare would be maximized by *excluding* abatement capital from the rate base. In fact, however, we see that abatement capital is almost always in the rate base, and it is assumed here that this practice will not change in response to the CAAA. Thus, it is assumed in what follows that abatement capital is placed entirely in the rate base (that is, $\varphi = 1$). The central question now concerns how emission allowances should be treated for ratemaking purposes.

Generally, this question has to do with the set of incentives that utilities should face when making compliance decisions. The CAAA envisions an economic setting in which utilities will be free to participate in the allowance market minimizing their cost of compliance. The spirit of the allowance trading scheme depends upon low-cost firms finding it in their interest to overcomply and to sell allowances at the same time that high-cost firms are purchasing allowances rather than scrubbing or switching. Utilities are being asked to respond to purely economic incentives when making these decisions, absent any regulatory distortions that may be present.

Of course, as noted earlier the CAAA deliberately sidesteps the issue of utility regulation. Specifically, then, the question of incentives for compliance planning has everything to do with how commissions alter the relative attractiveness of compliance strategies. This issue has often been described as the need to provide a "level playing field" for utilities. In short, if a firm that is high cost (and therefore should purchase allowances) in the absence of regulatory treatment finds that due solely to the way its compliance decisions are treated by the commission it should scrub, then the commission has provided the utility with a perverse incentive. This question is extremely complicated, and as utilities put together their compliance plans they will be considering myriad factors that are not addressed directly by this model. For example, systemwide least-cost planning (as noted in Chapter 4) will seek the lowest cost solution for the utility's entire system. The lesson that does translate to more complicated settings, though, is the need for appropriate incentives in compliance decisionmaking.

The utility regulator in this model must choose whether to place allowances in the rate base. Given the assumption that abatement capital is in the rate base, how will a utility respond if it learns that allowances (either originally allocated or purchased) are discriminated against in the sense that they are not in the rate base, or that they carry penalties of some other kind? This question is central to the incentive structure of compliance treatment, and to the compliance planning process utilities must soon complete.

The utility's profits are exactly the same as in the above section. Revenues come from the sale of electricity and allowances, and costs are incurred through the purchase of fuel, capital (both productive capital and abatement capital), and allowances. The firm is once again required to hold enough allowances to cover its emissions.[22] The difference between this section and the previous one is the ROR constraint the firm now faces. Economic profits are not allowed to exceed (s - r) times the rate base, where the precise makeup of the rate base is under the control of the commission. Let θ, a number between zero and one, represent the proportion of allowances that belong in the rate base. If $\theta = 1$, allowances are counted entirely in the rate base, while $\theta = 0$ means that no portion of the utility's allowances are in the rate base. Note that the rate base is equal to $(k_1 + k_2 + \theta\ell(p_\ell/r))$.[23]

In the mathematical derivation presented in Appendix D, the reader will notice a higher degree of complexity than was encountered in earlier sections. It is no longer sufficient for the firm simply to select an input combination. Now seemingly each decision, from the level of k_1 to use to the optimal emission level, feeds into the problem and helps determine how other choices should be made.

Equation (D-10) was the primary result of the mathematical work of the section, "Emission Allowance Trading Without ROR Regulation." In the absence of ROR regulation, the optimal decision was to set the marginal productivity of abatement capital in reducing emissions equal to the ratio of the cost of capital and the price of allowances (that is, $-\partial h/\partial k_2 = r/p_\ell$). The counterpart to that equation, when ROR regulation is

[22] And, as before, the environmental constraint is assumed to be effective, so that in this static version of the problem the utility will not want to own more allowances than it plans to use.

[23] As with the capital variables, care must be taken to value allowances properly in the (single-period) profit function and in the rate base. It is assumed that an allowance has an infinite life, generating in each period a coupon that may be redeemed (in that period or in any subsequent period) in exchange for the right to emit one ton of SO_2. The price of the one-period coupon is p_ℓ (which appears in the profit function), while the asset is valued at p_ℓ/r (which appears in the rate base). The capitalized value of the allowance, then, appears in the rate base calculation, while the yearly rental price appears in the profit function.

present, is equation (D-4) in Appendix D, which once again shows how the utility will strike a balance between compliance strategies.

As long as $\theta < 1$ the utility will face a distorted set of incentives *for compliance purposes*. In the absence of ROR regulation, optimal behavior required setting the left hand term equal to r/p_ℓ. Now, with regulation the optimal decision will usually not be the same.

In other words, the economic regulator may end up introducing a bias into the way the firm satisfies the environmental constraint simply because of how it treats allowances and abatement capital for ratemaking purposes. There is one situation in which this bias is not introduced. If allowances (both originally allocated and purchased) are included in the rate base at their full value (that is, if $\theta = 1$), then the utility will make its pollution abatement decisions in precisely the same way as in the absence of ROR regulation. A method for doing this is discussed in Chapter 9.

A last set of conclusions has to do with the way that emission levels and the level of electricity generation change in response to changes in θ. Two important facts may be stated with some confidence. First, based upon the results of this model, *for a given level of* q, whenever θ gets closer to one the utility will use less abatement capital. This makes intuitive sense because the firm is more willing to use allowances when they are placed in the rate base than when they are not. The more attractive allowances are, the more they are used to replace abatement capital as a compliance strategy.

Second, *for a given level of* k_2, whenever θ increases the utility will produce more electricity. As before, when q goes up the monopoly firm charges a lower price so consumers are able to purchase more electricity for a lower price, both of which add to consumer welfare. Of course, the utility once again must use more allowances to cover the increased emissions that accompany an increase in production. These additional allowances are made more attractive because they are included in the rate base.

The real question of interest, however, is not the way that one variable changes when one or more of the others are held constant. Instead, we wish especially to know how output, emissions, and allowance usage change in response to a change in θ. The result is anticipated by what was discovered in an earlier section. There, a favorable ruling for utilities (in which abatement capital was placed in the rate base) led to a reduction in q and an increase in the electricity price. Utilities were given an opportunity to earn higher profits when φ was increased, and in response they cut back their production levels.

The same outcome seems to result here when θ increases, and the same argument applies. The conclusion is more tentative, however. If θ is currently set at some level less than one and if the commission chooses to increase θ, then the rate base is increased and the utility may now earn higher profits. If it makes no changes in its operation, profits will not increase. To increase profits the firm would have to scale back production because of less demand for electricity with the welfare consequences described earlier. From a consumer surplus maximization standpoint, the commission should set $\theta = 0$ and should not include the value of allowances in the rate base.

At this point the competing interests of allowance market effectiveness on the one hand and ratepayer protection on the other become important. If a single utility were located on an island, and if its behavior had no effect on the allowance market, there would be no *economic* reason for setting $\theta > 0$. However, the allowance market will not function as well (if by functioning well we mean that traded volumes are high), given that abatement capital is almost sure to be included in the rate base, if allowances are not placed in the rate base. Setting $\theta < 1$ creates an automatic bias in favor of abatement capital (again assuming $s > r$). The entire analysis used the assumption that allowances are available in a perfectly competitive market. This assumption stretches credulity in any case, but would be significantly less likely if commissions were systematically to discriminate against allowance use in this way.

To sum up, given the fact that abatement capital is and probably will continue to be in the rate base, it is in society's interest for allowances to be *included in* the rate base. Otherwise the allowance market will be thinly traded and the large cost savings accruing to the market-based nature of clean air compliance will be squandered. However, regardless of how abatement capital is treated by commissions, it is in consumers' interest for allowances to be *excluded from* the rate base. Placing allowances in the rate base at some nonzero value will lead to increases in electricity prices and reduced electricity generation. These two outcomes both reduce consumer surplus and erode the welfare of ratepayers. Society may be better off as θ increases, since it causes an increase in profits. Whether this increase exceeds the loss in consumer surplus is not known.

The mathematical support for this conclusion is the most difficult encountered in this study. Though it is as yet imperfectly completed in Appendix D, the economic insight is identical to the case that appears in the section, "A Model of ROR Regulation with a CAC Environmental Constraint." It must be acknowledged that the decisions that utility regulators face are not purely economic. Rather, political constraints abound and must be satisfied. The conclusions of this chapter are to be taken in a positive sense. If the welfare positions of various groups are measured in the customary way, then the ratemaking treatment outlined above leads to the conclusions described. Even from an economic standpoint, the fact that $\varphi = 1$ means that the entire analysis of allowance trading is necessarily a second-best analysis. The starting point, because of economic regulation, is not perfectly competitive in the economic sense of this phrase.

Even with that much granted, the economic insights of this chapter still appear to have some value. Very little has been said in the past about the way that environmental and utility regulation affect each other, and this chapter has attempted to contribute materially to that difficult problem. In the following section a few important features of the problem that this chapter has not addressed will be mentioned. Some of these points appear elsewhere in the report, but it is well to provide an account of the important considerations and to suggest how extensions of this model could be used to study these as well.

Summary and Conclusions

It appears that the insight about the need for a "balanced" regulatory incentive system is of crucial import for the analysis of compliance decisionmaking specifically and allowance trading generally. Nevertheless, from this conclusion it is a short distance to a number of further suggestions and recommendations that may be stated with some confidence. The remainder of the section consists of discussing these points and offering some thoughts about further extensions of the research.

Numerous difficulties having to do with the accounting treatment of allowances must be addressed. For example, it appears likely that for accounting and tax purposes the initial allotment of allowances will be valued at a price of zero (as discussed in Chapters 5 and 9). It could also turn out that state utility commissioners will choose to value these allowances, for ratemaking purposes, in the same way. If they do, then the treatment presented here, in which the L_0 allowances that the firm was given at the beginning of the planning period were valued at p_ℓ, is not appropriate. Instead, the question of including the initial allowances in the rate base would be moot. Whether this occurs will have nothing to do with the use of allowances.

Taxation policy itself is a knotty issue that has been ignored here for simplicity's sake, but it cannot be ignored either by utilities or commissions. Just how tax treatment of allowances will alter the decisionmaking process is very difficult to predict. It is safe to assume, however, that a zero tax basis will reduce trading volume since the proceeds from an allowance sale would be subject to the 34 percent capital gains tax (which could only be offset by a capital loss). It is also difficult in the confines of the Averch-Johnson model this analysis has used to account properly for the details of revenue treatment and ratepayer ownership of certain assets. A more detailed model of managerial decisionmaking would permit these questions to be explored. Such an exercise is beyond the scope of this model.

Yet another important omission of this analysis is the fuel switching option for CAAA compliance. A utility compliance planner instinctively thinks about the decision between "scrubbing or switching" when attempting to form a compliance strategy or plan. This choice has not been treated in this model. While it would be no trivial matter, the present model could be extended to permit a careful analysis of the fuel switching strategy. When should a firm choose scrubbing over switching, and how do the conditions in the allowance market affect this decision? The primary required alteration would be to add more than just one variable input. This extension has been achieved for the ROR-regulated firm in the absence of environmental regulation,[24] and no new analytical techniques would be needed to make that extension here. Further complicating the switching option are fuel adjustment clauses that many utilities have available to them. This can also cause a bias in the utility's decisionmaking process, particularly if the utility is reluctant to invest in capital because of previous disallowances. This is discussed more fully in the context of ratemaking in Chapter 9.

Utilities and utility regulators alike exist in a world that is dynamic in essential ways. How much can one depend upon the insights of an expressly static model when studying this dynamic problem? Many authors have criticized the Averch and Johnson model by noting its inability to account for certain observed regularities in the utility industries, but it was not designed to explain events and decisions played out over time. The model used here, likewise, cannot speak to issues dynamic in nature. Still, its simplicity can be its chief advantage, for it yields insights obscured by the act of devising complex and elaborate substitute models.

The primary complaint against Averch-Johnson, of course, is that we do not always see $s > r$. Electric utilities no longer expect to earn an economic profit (price above average cost) on their capital expenditures. To be sure, realized rates of return has often fallen below the cost of capital, but to what extent is this due to a systematic violation of the A-J assumptions, and to what extent is it due to an incorrect forecast by utility managers about whether a given project will be placed in rate base? If a prudence review results in only a fraction of k_1 being recoverable, data will be generated that look like $s < r$. To a large extent, this has been the result of large scale (mostly nuclear) projects (see the discussion in Chapter 6). Over time this may seem to be an anomaly due to high interest rates and inflation and not as a permanent feature of regulation. If these factors are accounted for, the $s > r$ assumption may be reasonable.

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[24] See, for example, W. Erwin Diewert, "The Theory of Total Factor Productivity Measurement in Regulated Industries," in T. G. Cowing and R. E. Stevenson, eds., *Productivity Measurement in Regulated Industries* (New York: Academic Press, 1981).

In any case, even granted that the $s > r$ assumption is not always satisfied, the insights linking ratemaking policy to environmental compliance appear to be fairly robust to model specification. In future work, especially regarding compliance planning in a more general context, a dynamic model that takes into account the timing of utility investment and profits should prove to be an interesting extension.

Finally, as noted previously, decisions about CAAA compliance are made in an uncertain setting. Utility compliance planners do not know the price that allowances will be traded at, nor the future cost of coal and other inputs. Especially important is the effect that the allowance market itself will have upon demand for low-sulfur coal and its price. Everyone involved has reasons to make choices that are conservative in the sense that they do not put a utility or a group of ratepayers in jeopardy in the event that certain important uncertainties are resolved unfavorably.

It is worth noting once more in this regard the extreme importance of the uncertainty regarding property rights. Understandably, utilities can be expected to treat allowances with caution simply because they could disappear one day. It may be that commissions will seek above all to provide incentive systems that do not artificially favor one compliance strategy over another.[25] It is not so easy in the face of extreme uncertainty to specify what an incentive system like this actually will look like. Even if one could be sure that aside from considerations having to do with property rights, such a system of incentives was in place, a single act of Congress repealing or altering Title IV of the CAAA would obliterate the incentives' desirable properties. It may be appropriate and in the interest of ratepayers, however, to assume and plan that for the foreseeable future this will not occur.

The task of merging results on environmental regulation and utility regulation is formidable, and this chapter constitutes only an early first step. Concerns over protecting the environment are not going to go away soon, and utility industries will need to respond to other environmental controls in the future. Within a very short time, greenhouse gas legislation requiring a plethora of new restrictions may be passed into

[25] Such an incentive system is proposed in Chapter 9.

law. The groundwork laid here, then, promises to be helpful for some time to come and in widely diverse settings. The one lesson of this study is that new contours on the regulatory landscape make it necessary to reevaluate the regulatory treatment and its effect on utility decisions. In particular, decisions such as whether to include allowances in utility rate base and at what value (which can never simultaneously help both groups) are always going to be difficult.

CHAPTER 8

BENEFICIAL OWNERSHIP OF ALLOWANCES BY RATEPAYERS AND ITS REGULATORY IMPLICATIONS

As noted previously, § 403(f) of the Clean Air Act Amendments (CAAA) explicitly states that "allowances do not constitute a property right." Rather, §§ 402(3) and 403(f) provide that an allowance is merely a "limited authorization to emit sulfur dioxide." What's more, the Congress stated that the allowances are assets of the utility. The analysis in Chapter 1 led to the conclusion that an emission allowance was indeed a property right in the form of revocable licenses or permits, in which no reasonable expectation of a compensable property interest exists.

The more vital issue is who owns the property right. It is quite clear that Congress intended that the legal title and ownership of emission allowances be with the utility. Congress stated that the allowances are assets of the utility and directed the federal Environmental Protection Agency to issue the allowances to the owners (or the "designated representative") of the affected sources; that is the utilities. Stating that the utilities are legal owners of the allowances, however, is not the complete answer.

Ratepayers as Beneficial Owners of Emission Allowances

The system of allowance trading set up by Congress is an effort to balance both efficiency and equity concerns about the cost of acid rain compliance. Had Congress only been concerned about efficiency, it would have held an auction for the allowances, which would have helped set the market price of the externality (while reducing the federal deficit). Instead, Congress took into account equity issues such as who should bear the cost of acid rain clean-up. The allocation of allowances, including bonus allowances, reflects the equity judgement of Congress. Allocation is not meant as a give-away, a subsidy, or a "rob-Peter-to-pay-Paul" scheme, but an effort to cushion rate shock related to the cost of acid rain compliance. At the same time, an allowance market should lower the overall cost of acid rain compliance nationwide.

The fiduciary duty of utilities to act as trustees of the public, in particular of ratepayers, traces its origins to the duty of common carriers.[1] Indeed, the most basic notions involved in the regulatory compact--that of prudent expenditures and investments--draws on the concept of prudence in trust law in characterizing public utilities as enterprises conducted as trust for the benefit of the public.[2] There appears to be no traceable **direct** origin of the use of the concept of prudent investment respecting public utilities from the concept of prudent investment pertaining to trust obligations. Nevertheless, it is clear from the literature that legal scholars--including Justice Brandeis, the architect of the prudent investment test--who played a role in the early articulation of the prudent investment standard for public utilities were aware of the long-standing use of the prudent investment concept in trust law and likely borrowed from it.[3]

The theory of beneficial ownership can be traced to the law of trusts and contract law. The legal term "beneficial" means "tending to the benefit of a person; yielding a profit, advantage, or benefit; enjoying or entitled to a benefit or profit." This term is applied both to estates (as a "beneficial interest") and to persons (as "the beneficial owner").[4] Ratepayers have a beneficial interest in the utility's use of its

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[1] Edwin C. Goddard, *Cases on the Law of Bailments and Carriers of Service by Public Utilities* (Chicago: Callagan and Company, 1904 and 1928); and Edwin C. Goddard, *Cases on Principal and Agent* (St. Paul, MN: West Publishing Company, 1914).

[2] See Richberg, "A Permanent Basis for Rate Regulation," *Yale Law Journal* 31 263: 278-79 (1922). The connection between the law of trust and the prudent investment obligation of public utilities is discussed in greater detail in Robert E. Burns et al., *The Prudent Investment Test in the 1980s* (Columbus, OH: The National Regulatory Research Institute, 1985), Chapter 2.

[3] Ibid.

[4] *Black's Law Dictionary, Revised Fourth Edition* (St. Paul, MN: West Publishing Company, 1968), 198.

emission allowances under the regulatory compact. A "beneficial interest" means "profit, benefit, or advantage resulting from a contract, or the ownership of an estate as distinct from the legal ownership or control."[5]

Because regulated utilities are imbued in the public interest and have certain fiduciary duties to their customers under the regulatory compact, ratepayers are the beneficial owners of the emission allowances. The utilities are merely the legal owners of the allowances. As such, they are always obligated to act in the interest of the beneficial owners of the allowances, the ratepayers.

In this case, the benefit resulting from the regulatory compact (or, stated another way, the fiduciary duty of the utility that benefits the customers) is the ability of the utility to use its emission allowances to lower its cost of compliance. The fiduciary duty of the utility to engage in compliance planning and allowance trading is consistent with its overall obligation to provide reliable service to customers at the lowest reasonable cost. In return, the public utility receives an opportunity to recover its prudently incurred expenditures and to earn a reasonable return on its prudently incurred investment.[6]

As beneficial owners of the emission allowances, ratepayers are third-party beneficiaries to any sale or use of the allowances. Although ratepayers are not, as a group, privy to any contract entered into by a utility for the sale or purchase of allowances, they are beneficiaries because the contract was made to benefit them by allowing the utility to fulfill its regulatory compact to provide service at the lowest reasonable cost. However, ratepayers might not necessarily rise to the status of third-party beneficiaries able independently to maintain a breach-of-contract-suit civil action. Instead, the status of ratepayers as beneficiaries might be considered incidental by the

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[5] Ibid., 199.

[6] For a discussion of the regulatory compact, see Robert E. Burns, "Sorting Out Social Contract, Deregulation, and Competition in the Electric Utility Industry," *The Proceedings of the Sixth NARUC Biennial Regulatory Information Conference*, ed. David Wirick (Columbus, OH: The National Regulatory Research Institute, 1988).

courts in cases where a breach of contract for the purchase or sale of an emission allowance is alleged. In such a case, the utility would stand in the ratepayer's stead, just as in the case of a breach of a fuel procurement or construction contract.

This does not mean, however, that ratepayers have no enforceable rights should the utility fall short of its fiduciary duties to ratepayers to fulfill its end of the regulatory bargain. Instead, consumer advocates, state commission staffs, or the attorney general could advocate downward rate adjustments under the prudent investment or prudent expenditure test to remedy the utility's breach of its fiduciary duties and to readjust rates to a "just and reasonable" level.[7]

As noted in Chapter 3, emission allowances enable those utilities with a relatively low marginal cost of compliance to "overcomply" with the requirements of a single company stand-alone model and to generate "excess" allowances which then can be bought by utilities and other purchasers with a relatively high marginal cost of compliance to bring them into compliance. Given perfect knowledge of the marginal cost of compliance strategies and the market price of emission allowances, one would expect a utility to invest in compliance strategies to the point where the marginal cost of a compliance strategy equals the market price of an emission allowance. Any excess allowances could be sold on the market or banked for future use. If the utility was not in compliance and its control cost was already above the expected market price, the utility would buy allowances. By engaging in these strategies, a utility engages in an acid rain compliance strategy consistent with its duty to provide reliable service at the lowest reliable cost.

This simplistic conclusion is based on three faulty assumptions. The first, that the utility has perfect information, has already been pointed out. Although the marginal cost of well established compliance strategies can likely be forecasted with a reasonable degree of accuracy, in reality the ex ante market price of allowances is uncertain. Other problems related to uncertainty are discussed elsewhere. The second assumption is that the utility will be unaffected and neutral in its choice of compliance strategies by the

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[7] For examples, see Burns, *The Prudent Investment Test in the 1980s.*

state commission regulatory treatments. Chapter 7 shows that if state commissions simply graft emissions trading onto a traditional regulatory treatment of capital investment and expenditures there may be a significant bias against buying allowances for compliance.

The third serious problem relates to the problems of principal and agent. Even though the utility has a fiduciary duty to act in the interest of the ratepayer in its compliance choices, it will lack a sufficient incentive to do so with vigilance because any gains from its business choices will be passed through to ratepayers. Instead, there will be an incentive to do the minimum necessary to pass a prudence test. And, if the state commission has a form of preapproval of planned actions (Chapter 6), the utility will be reluctant to stray from the approved plan even if it makes sense to do so. In short, traditional regulatory treatment of allowances may not create sufficient incentive compatibility between the utility and the ratepayer to motivate the utility to act efficiently in its compliance planning and emission allowance trading.

The authors propose in the next chapter a regulatory treatment of allowances which would provide for a more neutral regulatory treatment of the allowances and would achieve the objective of incentive compatibility. The key to the proposal (explained in greater detail later) is the early uncoupling of the fiduciary relationship between the utility and ratepayers by having the utility buy out the ratepayers' beneficial interest in the allowances so the utility has complete ownership of the allowances, not just legal ownership. Then, the utility would have a greater incentive to act efficiently in its compliance planning and allowance trading.

Beneficial Ownership and Accounting for Gains on the Sale of Utility Property

The regulatory compact is not the sole source of authority for concluding that utilities are merely the legal owners of allowances. Historically, state public utility commissions have used a "burdens and benefits" or "risks and rewards" test in deciding how to treat the gain from the sale of utility property.[8] The relevant factors under that test are (1) who financed the investment in the asset, (2) who actually owned the asset, and (3) who bore the risk of any decline in the value of the asset. The use of the "burdens and benefits" and "risks and rewards" test shows that state public utility commissions have long treated ratepayers as beneficial owners of utility property, although they may have not used those precise words.

In the case of nondepreciable property, a majority of state commissions favor an above-the-line accounting treatment, holding that gain from the sale of land and other nondepreciable property should be the ratepayers because they have borne the risk of carrying the property. In such a case, the ratepayers become the beneficial owners of the property. This approach was endorsed as not being an uncompensated taking of utility property by the District of Columbia Circuit Court of Appeals in Democratic Central Committee v. Washington Metropolitan Area Transit Commission.[9] The case held that ratepayers are entitled to the appreciation in value of transferred properties because they bear the burden of maintenance, loss through normal wear and tear, and capital losses, while shareholders are uniquely protected from loss on nondepreciable property.

One might argue that emission allowances are a utility's nondepreciable property because they retain their usefulness until used, either in their year of issuance or in some future year. One might also argue that the burdens and benefits associated with the allowances ought to be borne by the utility so that the allowances become the property of the utility, because the utility bears the risk of a loss in value. However, if allowances are given above-the-line rate-base treatment until used, ratepayers who then bear the burdens and risks are entitled to the benefits and rewards.

Using a traditional ratemaking approach, however, many of the initial (nonbonus) allowance allocations might be put into rate base at a zero value, their original cost. For

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[8] For a more thorough discussion, see Diane Sponseller, "Accounting for Gains on the Sale of Utility Property," *Public Utilities Fortnightly* (May 16, 1985), 49-52.

[9] Democratic Central Committee v. Washington Metropolitan Area Transit Commission (D.C. Cir., 1973), cert. denied, 415 U.S. 935 (1974).

those allowances, there is no risk of loss and only possible gains. Because the utility might be risk averse, it might tend to bank zero-cost allowances and use them internally, even if it otherwise would have made economic sense to overcomply and sell the allowances. If the utility overcomplied and sold the allowances, ratepayers would have been allowed to benefit from the gain from the sale of a nondepreciable asset. In either event the allowances are intangible nondepreciable assets initially given to the utility because the utility owns an affected source, an existing generating plant. Typically, ratepayers are considered the beneficial owners of nondepreciable property because they ultimately bear the full risks and burdens of any losses from the sale of the property.

Because the emission allowances are issued to the utilities as owners of affected sources, an argument might be made that they should be treated the same as the affected source, that is, the generating unit that brought about their issuance. According to this argument, emission allowances should be treated not as nondepreciable property, but as an asset incidental to depreciable property. In such a case, one would expect state commissions to take the same approach on the sale of allowances as on the sale of depreciable plant. In the case of depreciable plant, state commissions tend to consider (1) who paid for the construction (including payments by means of a depreciation expense) and (2) the management prudence of making the sale. Then, the commission balances the benefits and burdens both to utility ratepayers and shareholders.

One typical example of a state commission treatment of gains on a depreciable asset can be found in Re Carolina Power & Light Co. decided by the North Carolina Utilities Commission.[10] In that case, the Commission ruled that gains from the sale of an interest in a generating unit should be used to benefit ratepayers through a reduction in rate base. The Commission rationale was that the gain represents cost-free capital upon which the ratepayer should not be expected to pay a return. Because the sale was an extraordinary and significant event, the Commission allowed it to be amortized over a three-year period.

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[10] Re Carolina Power & Light, 55 PUR4th (NCUC 1983).

A similar approach was taken by the New Hampshire Public Utilities Commission in deciding whether and how ratepayers should benefit from the sale of investment tax and energy tax credits associated with a plant.[11] The Commission determined that ratepayers should benefit through a reduction in the company's rate base rather than through a recovery over an amortization period. The Commission's rationale was that the gain from the sale of the tax credits was a source of zero-cost capital for which no return should be allowed. Thus, a reduction in the company's rate base was appropriate because it was consistent with prior treatment of zero-cost capital, was not confiscatory, and would burden neither ratepayers nor shareholders.

Here is how this approach would apply to emission allowances. A state public utility commission would recognize the gain from the sale of an emission allowance. If that emission allowance was not one that had been acquired but was part of the initial allowance issuance by the EPA, the commission would use the gain on the sale of the allowance to reduce the utility's rate base. Because there would be no cost for the allowance, the gain from the sale of the allowance would be the sale price less any broker fees or transaction costs, if any.

This approach would seem sensible if the allowances were "freed up" for sale because of a capital expenditure on the part of the utility. The sale of excess allowances to offset the capital cost of a scrubber or other capital expenditure for pollution control abatement seems sensible. However, it might prove less sensible to decrease the rate base if the sale of allowances was made possible because the allowances were freed due to a compliance action that was not a capital expenditure in rate base (for example, if the allowances were freed because of the use of low-sulfur coal or cofiring with natural gas). A public utility would be hesitant to take any action to reduce its rate base, and, all things being equal, will tend not to sell allowances but to bank them. This would be the case especially when the source of the freed allowances is an expenditure. It might be more palatable to the utility if an expenditure "freeing up" allowances was offset by the revenue generated by the sale of the emissions market.

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[11] Re Public Service Co. of New Hampshire, 57 PUR4th 563 (1984).

Unfortunately, no immediate case law guidance is available to show how to treat gains from the sale of plant that is not in rate base or that is being phased in, although logically any below-the-line treatment or exclusion of a plant from rate base would result in below-the-line treatment for gains on the sale of the utility asset. If a plant is excluded from rate base, fully or partially, and no construction work in progress was collected from ratepayers during the plant's construction, then there would be no basis for contending that the ratepayers are beneficial owners of the plant or its associated assets; that is, the emission allowances associated with the plant. A knottier problem would be if a plant is partially (say as a result of a phase-in) or fully excluded from rate base because it is considered overcapacity and not "used and useful" even though the plant is on line and in service, generating electricity at a low variable cost so that it displaces in the dispatch order older, fully depreciated plants with emission allowances associated with them.

Who should benefit by any gain from the sale of freed emission allowances? Should it be the ratepayers who bore the burden of the older, fully depreciated coal plant that the freed allowances are associated with or should it be the shareholders who are bearing most, if not all, of the burdens and risks of financing the below-the-line asset that enables the allowances to be freed? The principle that benefits should follow burdens and rewards follow risks is tested by this example. On the one hand, the burden and risk of the affected plant fell on the ratepayers. On the other hand, the burden and risk of the more efficient plant that frees allowances is partially or wholly on the utility.

There are several different methods of handling the benefits, such as treating the purchase of power from a plant not fully in rate base as though it came from a third party. This method would result in ratepayers retaining the benefit of the allowances, because the gain from the sale of the allowances might be used to offset the price of purchased power. However, the utility is likely to contend that because the allowances were freed as a result of the power purchased from a plant not in rate base, the benefits belong to the company. Unless the utility can show that purchased power is typically traded for allowances on a one-to-one basis, it is unlikely that the utility will prevail. However, there remains a problem if allowances are freed up when there is no capital recovery in the purchased power rate. There is no simple way to untangle this Gordian knot, so the best course of action might be to split the benefits from the sale of the emission allowances.

A second method of allocated gains from the sale of depreciable property has been used by the Idaho Public Utilities Commission.[12] In a case involving the sale of coal-fired units, the Commission held that the gain from the sale should be allocated in proportion to the depreciation that has taken place on the plant. The theory is that the depreciation expense represents the extent to which ratepayers have assumed the burden by buying into the plant. Thus, when a plant is sold before it is fully depreciated, shareholders benefit proportionately to the extent that the plant *has not* been fully depreciated, and ratepayers benefit to the extent it *has* been depreciated. The Commission's rationale for using this method was that it was the only reasonable means of apportionment to make compensation of the rewards and benefits of gain commensurate with the risks and cost burdens of shareholders and ratepayers. The Commission also recognized that using this method would require it to ensure that assets are not prematurely sold by the utility to acquire gain on the sale while requiring new, more expensive assets to be built or bought. Of course, this method assumes that the plant was or is in the rate base.

Here is how this method would work for emission allowances. As an asset associated with a particular affected plant, the commission would examine the proportion to which the plant is depreciated to determine what part of the gain on the sale of emission allowances goes to the stockholder and what proportion goes to the ratepayers. One would expect that most of the gain would be issued to the ratepayers because of the utility's ownership in an older underlying asset--for example, an older coal-fired plant--is likely to be fully depreciated. In this case, the gain on the sale of the emission allowances associated with the fully depreciated plant would go entirely to ratepayers. Again, however, this treatment, absent any other action from the commission, might bias

[12] See Utah Power & Light Co., Case No. U-1009-114, Order No. 16788 (Idaho PUC, September 30, 1981).

utilities into banking allowances that otherwise would have made better economic sense to sell.

We have shown that although the utilities are the legal owners of the emission allowances, ratepayers are, to some extent, the beneficial owners of the allowances. State commissions' regulatory treatment of the gain from the sale of the allowances that assigns all or part of the gain to ratepayers is consistent both with the theory of beneficial ownership and prior state commission treatment of gains from the sale of utility assets. However, the typical regulatory treatments noted above could result in uneconomical banking (hoarding) of allowances as well as in a possible bias favoring capital-intensive investments to "go-it-alone" and free allowances rather than adopting compliance strategies that require a low capital investment or that can be expensed.

CHAPTER 9

RATEMAKING AND ACCOUNTING FOR ALLOWANCES AND COMPLIANCE COSTS

As was illustrated in Chapter 7, the regulatory treatment of compliance costs and allowances will significantly affect both the utility's CAAA compliance decisions and the cost of compliance. The ratemaking treatment in particular can influence, for example, the decision whether to invest in pollution abatement technology (scrubbers or clean coal), to switch to low sulfur fuels, to invest in conservation to reduce emissions and earn bonus allowances, and/or to purchase allowances. The commission can develop a regulatory treatment of allowances that gives the utility an incentive to select compliance options that are in the long-term interest of ratepayers. Indeed, for reasons explained in Chapters 3 and 7, it is in the ratepayers' interest to adopt incentive mechanisms that foster the development of a market. It is now apparent to many observers that the actions of the state commissions and FERC will greatly influence the success or failure of the allowance market.

A major difference between the 1990 Clean Air Act Amendment's Title IV provisions and earlier command-and-control environmental regulation is that now the utility is allowed considerable discretion in how to comply. A utility, facing an array of compliance options, will base its decisions in part on expected future regulatory conditions. Because the utility and commission have no previous experience with a mechanism like the allowance system or with the treatment of compliance cost when the utility is given this level of discretion, the utility will likely consider three sources of information about the possible future regulatory treatment when assessing its options.

First, the commission's past treatment of capital expenditures and fuel price increases will likely be used in assessing and predicting future commission action. This includes the commission's past treatment of pollution control equipment, fuel cost recovery, and new plant construction. Second, the commission could also intentionally or unintentionally limit or bias the options of the utility. The commission (or state legislature, as has occurred in one state) could intentionally do this by stating directly what options are to be considered. An unintentional bias could occur if the commission states, for example, that pollution control equipment will be ratebased. Then some uncertainty is removed from this choice and thus there is a corresponding reduction in risk--hence, the expected cost relative to other options making this option relatively more attractive. It is in the interest of ratepayers for the commission to encourage utilities to consider the widest array of suitable options, including the purchase of allowances and the sale of allowances to reduce compliance costs when it is cost effective.

And third, current ratemaking conditions also may affect the utility's choices; the commission again may not intend the final results. For example, if the market cost of capital is greater than the allowed rate of return (or the expected rate before a rate case), the utility may have a bias against capital investments.[1] Of course, as was illustrated in Chapter 7 this bias can work in the opposite direction if the market cost of capital is less than the allowed rate of return--the Averch-Johnson bias.[2] Another example of a bias from current ratemaking practices can occur if a fuel adjustment clause can be used (or is believed able to be used) by the utility. In this case, some of the risk from switching to low sulfur coal or other fuel is reduced; this could bias the utility's decision in favor of fuel switching, which may not be the lowest cost option.

In all three of these cases the utility's perception of past and future regulatory treatment is as important as the events themselves. In the first case, past regulatory treatment, the utility may feel that it was treated unfairly with a large capital expenditure. This may cause the utility to be reluctant to take on a large investment. In the second case, the utility may be reluctant to accept the commission's stated intentions

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[1] Paul L. Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation," *Journal of Law and Economics* 17 (October 1974): 291-327. This is explored with respect to the CAAA in D. Bohi and D. Burtraw, "Utility Investment Behavior and the Emission Trading Market," Discussion Paper ENR91-04 (Washington, D.C.: Resources for the Future, January 1991).

[2] H. Averch and L. L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* 52 (December 1962): 1052-69.

because of the length of time involved with these decisions and the uncertainty of future commission actions. The third case can involve the utility's own perception of future events that are beyond its and the commission's control, such as interest rates, fuel prices, construction costs, and so on.

This emphasizes the need for the utility to select flexible compliance strategies and for the commission to provide as much predictability and flexibility as feasible in its regulatory treatment. From the commission's standpoint, this involves employing a regulatory treatment that provides an incentive to the utility to minimize its compliance cost, does not bias the utility toward particular options, and allows flexibility for unforeseen events. To facilitate this, the commission can establish credible guidelines for the utility to consider when making its decisions.

Ratemaking Treatment of Allowances

Commissions may develop an array of rate treatments of allowances and compliance cost to suit a variety of situations. These situations include the rate status of the electric generating unit that receives the original allocation and the system-wide investment required to comply with the CAAA.

The commission may use the rate base status as a guide to determine the beneficial ownership of the allowances, as discussed in Chapter 8. This would explicitly recognize the manner in which the CAAA allowances are allocated; that is, to a generating unit based on emissions and fuel use from 1985 to 1987 (except for special provisions or appeal to EPA). If, for example, the unit is not ratebased at all or is being phased-in over time, the commission may decide that the original allocated allowances are owned either entirely or partially by the utility. Conversely, if the unit is in the rate base and depreciation expenses have been or are being passed through to ratepayers, then the commission may determine that all of the benefit from the unit's allowances belong to ratepayers or in proportion to the amount depreciated.

The commissions may consider the circumstances of their particular state or utility, recognizing that there is considerable variation across states and across utilities of the amount of required reduction or allowance purchases. As illustrated in Chapter 2, some states are required to make considerable adjustments while others have relatively little or no immediate adjustments. Commissions may consider this overall compliance requirement when deciding on the rate treatment. Even within a particular state the treatment may vary since utilities are affected differently. It may be appropriate for states with little or no immediate impact to consider their options now, rather than waiting until future capacity expansion or legislation (for example, global warming legislation with carbon dioxide trading) brings the issue before them.

Developed below are two general approaches to ratemaking treatment of allowances and compliance costs. These approaches were developed to be consistent with current regulatory practices in the country while being consistent with the particular characteristics of allowances and the nascent allowance market. Two different approaches are discussed here. The first takes a traditional regulatory approach to allowances and compliance costs. This approach was developed by analogy, to the extent possible, with similar assets. However, recognizing that there may be no perfect analogy and that a traditional method may cause perverse (albeit sometimes unintended) incentives, a second alternative is developed. This alternative builds on the market oriented nature of the allowance system and the intent of the CAAA to minimize the cost of compliance. This second alternative is based on an incentive regulatory approach.

Traditional Regulatory Approach

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 (as in Chapter 8) that ratepayers 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.

Allowances from the utility's initial endowment or allocation created by the CAAA will not necessarily result in an accounting gain or loss if used internally by the utility. Because those allowances have an initial zero-cost basis, they could simply be expensed at their cost, zero, when used internally. When allowances are "freed" for a sale because of a utility investment or because of switching to lower sulfur fuel, any gain could be applied first to offsetting the cost of compliance (or overcompliance) strategy.

For example, if the compliance strategy involved a scrubber, the device would most likely be included in the utility's rate base. 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. (Later in this chapter, a method is presented to share the gains between ratepayers and the utility.) A commission could maintain this regulatory approach until the utility's pollution control facilities in rate base become zero.

If gains from the sale of allowances were to reduce the utility's ratebased investment to zero, a commission might provide for sharing the excess between shareholders and ratepayers. Shareholders would benefit from the utility's prudent investment decisions that freed up the pollution allowances in the first place. Ratepayers would share in the gains because the source of the initial allowances was underwritten by rates. It is likely, however, that it would be several years, if ever, before the cost of the compliance investments could be completely offset by allowance sales (depending on the cost and depreciation rate).

A similar approach could be taken for utility investments in conservation that free allowances. Some type of split-the-savings approach might provide the utility with a "revenue neutral" and economically appropriate incentive to invest in the most effective conservation methods first. Allowances produced by a utility's investment in conservation should offset the cost of the conservation, and then be split between ratepayers and shareholders.

If the allowances were freed because of fuel switching, one could argue that the proceeds from the sale of allowances should be applied against the expected higher cost of low sulfur coal and the cost of any capital improvements necessary to allow the utility to switch fuels. In particular, it is conceivable that the long-run price of low sulfur fuel will include a premium because of increased demand stemming from the CAAA. At the same time, high sulfur fuels could be discounted. Commissions may pass through to ratepayers gains from the sale of allowances to the extent that the prices paid for low sulfur fuel exceed those for high sulfur fuel. This is because ratepayers provide the source of funding for the switch from high sulfur to low sulfur fuels. (In the unlikely event that switching from a high sulfur fuel to a low sulfur fuel results in decreased costs, a commission might wish to reexamine the prudence of the utility's earlier fuel procurement policies.) If the sale of emission allowances results in profits in excess of the difference in price between high sulfur and low sulfur fuels, a regulatory commission might again consider rewarding the utility for its fuel procurement policies by allowing the shareholders to benefit in some share of the remaining gains. Gains from freed allowances due to fuel switching could be partially or fully flowed through to ratepayers using the fuel adjustment clause.

A utility that purchases allowances may realize a gain or loss from the allowance if it is resold. For example, an allowance might be purchased for $600 and sold at the end of the year for $550, a net loss. Because the allowance was bought and sold as a security and not used internally, a traditional regulatory approach would suggest that the utility should bear the loss below the line. Similarly, if the utility bought an allowance for $550 and sold it at the end of year at $600, the utility should receive a below-the-line gain. However, commissions may not care to become involved in the appropriateness of the price of an individual allowance. Since 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.

Limitations to the Traditional Methods

These traditional ratemaking treatments may introduce an unintended bias in favor of compliance options that are not necessarily the lowest cost solution. The analysis of Chapter 7 illustrates how there can be, under certain conditions (primarily when the rate of return exceeds the cost of capital), a bias toward large capital expenditures. 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. As noted earlier, at this writing, all state commissions except one allow pollution abatement investment into rate base. Therefore, if there is a virtual guarantee that the investment will be ratebased, initial allowances will not be, and the sale of any allowances will be used to 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. 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.

Also, there is the possibility that the utility will have a preference for purchased allowances and attempt to replace zero-cost, nonratebased allowances with market-priced allowances that earn a return. That is, they simply try to increase their rate base (and return) by increasing the value of the allowance inventory. This, of course, depends on the inventory method used for ratemaking purposes, such as last-in, first-out; first-in, first-out; or average. FERC has proposed a weighted average inventory method to avoid a possible distortion in incentives caused by the inventory method. (This proposal is discussed later in this chapter.)

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

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 intended (as described in the "ideal world" of Chapter 3). An incentive-based ratemaking system, in contrast, can be designed to give the utility an incentive to adopt a compliance strategy that is in ratepayers' interest by allowing the utility to benefit from its good decisions, but still be held accountable for faulty ones.

Incentive Ratemaking Treatment of Allowances

Based on Chapters 7 and 8, a three-step incentive ratemaking treatment of allowances can be developed. Five assumptions are made about allowances and the ratemaking treatment of allowances: (1) allowances will be valuable assets to the utility (and hence ratepayers), (2) the commission is neutral with respect to the utility's particular compliance options--including technology and fuel choice,[3] (3) an economic incentive provided to the utility can induce the utility to adopt the lowest-cost option, (4) an allowance market will develop and provide regulators with useful price information, and, (5) the regulators' (state and FERC) actions will influence the development of the allowance market, including the price and availability. This alternative is suggested as a means to develop a ratemaking procedure that introduces no bias favoring any particular

[3] Several states have enacted legislation to ensure the use of in-state coal and protect miners' jobs. Such political decisions and how states factor this into their decisionmaking process is not dealt with here. In this analysis it is assumed that the commission is not interested in a specific technology or fuel, except the lowest cost ones.

compliance option, gives the utility an incentive to minimize its CAAA compliance costs, and is designed specifically to take advantage of the market-based system of allowances.

While no one can be certain of the future price and availability of allowances, there are several indications that they are likely either to hold their value or increase in value over time. First, many utilities will require more than their initial allotment of allowances and will be required either to purchase them in the market or reduce their emissions. Since not all units face the same reduction costs, utilities with relatively high-cost units should either purchase from others with comparatively low compliance costs, overcontrol at their own lower-cost units, or both. Second, all future fossil fuel power plants (not provided for in the CAAA) will have to purchase all of their needed allowances. These allowances will have to be obtained from affected sources willing to sell allowances they generate through overcontrol or retirement of their units.

Since allowances are a factor in the production of electric power from fossil fuels, any future growth in the demand for fossil power facilities will increase the demand for allowances. Third, the dynamics of the market (as with any competitive market) should be that even with considerably more utility overcontrol than expected (which appears to be the case so far with phase I units), the increased number of allowances on the market would cause the price to fall below the incremental control cost for many fossil fuel users (as explained in Chapter 3). Conversely, if the uncertainty causes many to retain their allowances, then the price should rise freeing additional allowances both from those where it is now feasible to overcontrol (because of the higher price) and from those holding banked allowances.

This alternative treats allowances for ratemaking purposes held by the utility as nondepreciating assets with a *nonzero* basis. This would be similar to an inventory account such as for coal. Like coal, the utilities will expend allowances in the production of electricity that involves SO_2 emissions and will have to hold sufficient allowances to cover their emissions. These allowances will come from the utility's systemwide initial allocation and purchases. The allowances that are purchased, again like coal inventory, can be valued at the contracted or historical price, if considered reasonable by the commission. Also, the number of allowances counted in inventory (and included in rate base) would be the amount determined to be reasonable by the commissions for normal operation of the utility's facilities plus some amount for unforeseen circumstances. The incentive mechanism described below, however, will give the utility an incentive to bank only the number of allowances needed for future use or hold because of an expected future rise in the price of allowances. Also, this method is intended to remedy a source of distortion in incentives to the utility from the ratemaking treatment and valuation of the initial allocation of allowances.

Step One: Utility Buy-In

One means of creating an unbiased and incentives-based ratemaking treatment would allow the utility to "buy in" to the allowance system as a ratebased asset. In the first step of this proposed allowance treatment, the commission would determine the proportion of the value of the asset that belongs to ratepayers and what should go to the utility's shareholders (based on a method for determining ratepayer beneficial ownership of the generation asset described in Chapter 8). Also, the commission would determine the fair market value of the allowances, based on actual contracts signed by the utility, external market information, or the EPA auction prices (provided sufficient information is made available). This value (the determined fair market price times the quantity of allowance) would be entered as a ratebased asset. This could be balanced as a regulatory liability to ratepayers (asset value times the proportion determined to go to ratepayers; the accounting for this, as proposed by FERC, is discussed at the end of this chapter).

It is important that for the valuation of allowances a fair market price for allowances be determined rather than using the utility's own internal control cost. This way the utility will base its decision on the number of allowances to buy, sell, and bank on the relative cost of allowances compared with its own cost of emission control. Basing the allowance value on the utility's control cost alone could provide the utility an incentive either to inflate its control costs or not minimize them. (This external price signal is important in the next step of this incentive treatment as well.)

Table 9-1 provides an example of how the first step of this method would work for the allocated allowances. In this example, the utility will receive an allocation of

TABLE 9-1

EXAMPLE OF INITIALLY ALLOCATED ALLOWANCE INCENTIVE TREATMENT

Year	Allowance Value ($)	Annual Return ($)
1995	20,000,000	1,600,000
1996	20,000,000	1,600,000
1997	20,000,000	1,600,000
1998	20,000,000	1,600,000
1999	20,000,000	1,600,000
2000	10,000,000	800,000
2001	10,000,000	800,000
2002	10,000,000	800,000
2003	10,000,000	800,000
2004	10,000,000	800,000
2005	10,000,000	800,000
2006	10,000,000	800,000
2007	10,000,000	800,000
2008	10,000,000	800,000
2009	10,000,000	800,000
2010	10,000,000	800,000
2011	10,000,000	800,000
2012	10,000,000	800,000
2013	10,000,000	800,000
2014	10,000,000	800,000

Assumptions:

Phase I allocation = 80,000
Phase II allocation = 40,000
Allowance Fair Market Value = $250
Allowed Rate of Return = 8.00%
Discount Rate for NPV calculation = 5.00%
Net Present Value of Income Stream = $13,433,350

80,000 allowances in phase I and be reduced to 40,000 in phase II. The commission determines that ratepayers are the beneficial owners of all the allocated allowances. The commission also determines that the fair market value for allowances should be $250 and that the discount rate for calculating the stream of allowances' net present value is 5 percent and the planning period is twenty years. This discount rate can be based on, for example, long-term government bonds, utility's cost of capital, or some other means of determining long-run opportunity cost. The planning period can be any length in time, but should be sufficiently long to allow long-term compliance decisions to be made by the utility. At this time or in a previous rate case, the commission in this example determines that the utility's rate of return should be 8 percent. The allowance value in rate base would be the commission determined price times the number of allowances allocated for the year (column 1 in Table 9-1)[4]. The income stream is then the allowance value times the allowed rate of return (column 2). In this example given these assumptions, the net present value (NPV) would be $13,433,350.

Under this proposed method, the utility would "purchase" this stream of income by paying ratepayers the NPV (as, for example, a reduction in rates over time). The commission can determine the number of ratepayer allowances using the reasoning of Chapter 8. This is similar to the utility purchasing a coupon bond with an annual or some other periodic payment. Once the utility has purchased this income stream, it would be allowed, within certain limitations, to use them at their own discretion for compliance. This would include sharing any profit on their sale or incurring a loss. Beneficial ownership of the allowances, unless purchased outright by the utility, would remain with the ratepayers. Utilities may be given the option of purchasing some or all of the allowances in exchange for more discretion in their use. This could lead to a

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[4] In order to keep this example simple, it has been assumed that all the allocated allowances in a given year are used or sold, that is, no banked allowances are carried over from previous years. In actuality, of course, there will most likely be some banked allowances. It is also assumed that the allowances are received at the beginning of the year and deducted or sold at the end. Relaxing either of these assumptions, while making the problem more complex, would not change the analysis.

policy option that is essentially a deregulation of the firm's compliance actions. However, for many utilities this would impose a heavy financial burden and commissions would have to guard against cross-subsidization between the regulated and unregulated activities of the firm. Under such a policy, the utility may attempt to maximize the number of allowances for sale and shift cost to the regulated activities of the utility.

Steps 2 and 3: Market Test of Compliance Costs and Utility Incentive

As with any ratemaking treatment, the commission will still need to remain vigilant concerning the utility's compliance costs to insure that unnecessary costs are not passed through to ratepayers. In the second step of this proposed incentive method, compliance expenditures would be tested against the market value of allowances to determine whether the least-cost strategy is or was adopted. This would be based on the system-wide average compliance cost of the utility.[5] In the third step, if the average compliance cost (scrubber, switching, CCT, and so on) is less than the market price of allowances, then the utility is allowed to profit on its sale. The gain to the utility would be up to the allowance price minus the compliance cost minus the return that would have been received if the allowances were retained by the utility. Applying the same discount rate, this return would be allowance price times the allowed rate of return, or \$20 (8% x \$250) in the above example. (The gain from selling allowances when the control cost is below the market price of allowances is illustrated in Figure 3-2 in Chapter 3. It would be this gain, net of transaction costs, that would be shared under this proposal.

Again applying the above example, if the utility's control cost was \$225 per ton of sulfur dioxide and it could sell allowances for \$250, then, if the utility believed that the

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[5] Note that if the utility is using incremental control cost in its planning process, as described in Chapters 3 and 4, to determine which compliance option to adopt, then the average control cost across the utility's system would actually be the average of the incremental control costs. It is referred to here, for ratemaking purposes, as simply the average control cost and assumed that in the planning process incremental cost was used.

price of allowances would remain the same or fall in the future, the utility would sell the available allowances and receive a gain of up to $5 ($250 - $225 - $20) per sold allowance (presumably, the utility would still need to retain some allowances for its own use). If the utility sold half its allocation for each of the twenty years then, using the same discount rate of 5 percent, the net present value of the gain on the sale would be up to $1,679,169. How much of this the utility would be allowed to retain would depend on the portion the commission allows the utility to retain and what is to be given to ratepayers. A percentage sharing arrangement could be determined in advance.

Therefore, if the utility can earn more than its rate of return by selling its freed allowances, then it would be allowed a below-the-line gain on the sale (also net of any transaction costs and ratepayer share). If on the other hand, the control costs are above the market price, the utility can only recover the market price from ratepayers. The difference in this case would be a below-the-line loss to the utility.

Since the utility under this method is allowed to retain some or all of the gain or incur any loss on the sale of allowances, there is an incentive to reduce the capital and operating cost of compliance. The lower the control cost (and the higher the sale price) the greater the gain on the sale. If the utility does nothing with the allowances, it will earn just its rate of return until the allowances are used. When allowances are used, they would be deducted from the rate base (at the value the allowances were entered at) that can be adjusted periodically (as discussed below, FERC is proposing a monthly adjustment). A periodic adjustment would avoid delays that would result with no adjustment until a rate case. What is driving the utility's decisionmaking and planning now is decreasing the cost of compliance and maximizing the price of sold allowances, which is also in the interest of ratepayers.

The utility would no longer, of course, receive the income from sold or used allowances as a ratebased asset. Sale or use of allowances would likely involve deducting the amount from an allowance inventory account (this has also been proposed by FERC). Any purchased allowances would simply be added to the allowance inventory and deducted as used. Purchased allowances would be evaluated the same as any other compliance option; in this case the purchase price would be compared to the commission determined fair market value. The commission would have to make adjustments to the rate base for any allowances deducted by EPA for the auctions and sales (as described in Chapter 1).

With this type of incentive mechanism, the commission does not prescribe or approve the specific control technology planned or used by the utility, which is only measured against the average compliance cost and an assumption of prudence unless shown otherwise (Chapter 6). This gives the utility an incentive to reduce its costs by adopting or developing innovative technology and operating its compliance assets in an efficient manner.

Under this incentive mechanism the commission determines the allowance price based initially on an estimation of the value of the allowances and, eventually, on the market price. This value or price becomes a benchmark or a standard of prudence to measure the performance of the utility and the reasonableness of their allowance purchases and sales. This standard can be used with the traditional method described above as well. Commissions may want to wait and see how the market develops first before committing to such a standard. As noted earlier, however, the commission's own actions will determine the allowance market's outcome. Committing to such a system early may help induce economic compliance and allowance trades as well as facilitate the market's development.

This benchmark standard should be posted in advance and the utility given reasonable assurance that it will be applied objectively. The benchmark could be set and adjusted annually at the beginning of the year during EPA's true-up period. The usual standard of prudence would still apply to costs that are within the control of the utility, as described in Chapter 6. That is, the utility would not be responsible for factors beyond its control but accountable for the things that are within its control.

Other incentive mechanisms, of course, can be developed. For example, a commission may decide that the bias problem caused by the initial allocation of allowances is not a problem since the state or utility will receive only a small number of allowances. In this case, the commission may skip step 1 of this mechanism and adopt some form of steps 2 and 3. Most likely, however, any incentive mechanism will involve some kind of benchmark standard that is compared with the utility's actual control cost.

In summary, this incentive-based ratemaking approach has three steps. First, the utility pays ratepayers for their beneficial interest in the allowances. In exchange the utility receives a stream of income from the allowances based on the value determined by the commission. This has the consequence of neutralizing the negative effect of having the allowances in the rate base at zero value. Second, the utility is allowed to recover from ratepayers the compliance cost *up to* the benchmark value of allowance determined by the commission. And third, the difference between the benchmark and the actual compliance cost, if the control cost is less than the benchmark, is shared between the utility and ratepayers in a proportion determined by the commission. If the control cost is greater than the benchmark, the utility can only recover the benchmark value.

Application of an Allowance Incentive Mechanism

This mechanism can be applied broadly to a wide variety of situations. In the case of a utility that will be receiving a relatively large amount of allowances from EPA and faces considerable compliance costs, it is likely that a commission would find that most of the units are older, ratebased, and are partially or fully depreciated. This method, therefore, would provide the correct incentives to the utility and help hold down the cost to ratepayers. In this situation, a utility with relatively high control costs would benefit from purchasing allowances. Conversely, a utility with allocated allowances and relatively low control costs would be encouraged to overcontrol and sell allowances.

A few utilities, because of state environmental laws, have already overcomplied with phase II of the CAAA and incurred and possibly recovered or are recovering the cost in the traditional manner. This mechanism would free the utility in this situation, once its ratepayers have been compensated, to sell its excess allowances or hold them if it believes the price will rise in the future. Alternatively, in the situation where the control costs of the utility have already been recovered from ratepayers, the commission could decide to simply pass the revenue from the allowance sale to ratepayers, net of transaction costs.

In the case of utilities with few allowances and little or no compliance cost in the near future, the focus is on the optimal number of allowances to bank. Again, this method will give the utility an incentive to hold what it believes to be the best number of allowances given its assumptions about the future. Since it is now in the interest of the utility to be careful and because the utility is in a position to know its system's opportunities, this method should result in decisions that are also in the interest of ratepayers.

Some units receiving allowances are "requirements" units or plants; that is they are dedicated to specific requirements customers such as an industrial or municipal power authority. In these situations the utility would compensate that customer directly since they would likely be determined by the commission to be the beneficiary.

Finally, this method may be well suited to the case of a multistate utility or holding company. In cases involving wholesale transfers of power, FERC will have to determine the beneficial ownership and beneficiaries of the allowances received and held by these companies. It may be considerably less complex to determine first the beneficiaries and arrange for their compensation than doing it on a case-by-case basis. Presumably, the ratepayers determined to be the beneficiaries would be compensated, and the cost of the allowance added to the cost of providing and generating the power. This would require, however, a considerable amount of cooperation between the states (and, perhaps FERC) that the utilities operate in, since the states may have different views of who "owns" the allowances and should receive the compensation. At the very least, this method makes this process more explicit and transparent to the parties involved. The benchmark standard described above could be applied regionally, with several states agreeing on the price or estimated value.

The purpose behind this incentive mechanism is to allow the utility to earn a return on the allocated allowances and avoid the perverse incentives that occur when they are not included in rate base, and also compensate ratepayers (the beneficial owners) for the allowances that the commission determines "belong" to them. As noted, the method presented here to determine the gain or loss on an allowance transaction (that is, taking the difference between the posted allowance value or price and the utility's compliance cost) can be implemented without the step of including the allocated allowances in the rate base. The commission would simply use the difference between its benchmark and the utility's control cost and then determine the share of the gain or loss to the utility and ratepayers. In this case, however, the distortion described in Chapter 7 and earlier in this chapter will not be corrected.

Another implementation problem would be measuring the compliance cost. While the calculation is somewhat straightforward[6], the commission should be alert to the potential of understatement or shifting of costs by the utility.

Thus far, commissions are finding that their own decisions are having a profound effect on the market. Because of the more than expected overcontrol for phase I compliance, the forecasted price of allowances has fallen considerably (one organization's surveys found that the respondents' expected 1995 price of allowances fell from about $650 early in 1991 to about $450 in early 1992.[7]) If utilities continue to adopt a go-it-alone strategy and fail to consider allowances as an option (both buying and selling), then the failure of the market may become a self-fulling 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 used more. 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. (As of this writing, there have been two allowance transactions.)

For these reasons, commissions may want to consider at this early stage in the development of the allowance market the use of modelling techniques to forecast a close approximation of a fair market value. Alternatively, the commission may choose to set

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[6] Calculation of compliance costs will be discussed in a subsequent NRRI report.

[7] AER*X, Inc., "Expected Allowance Price Levels Continue To Drop," *Air Credit Advisor* 2 no. 1 (First Quarter 1992).

the benchmark at the firm's control cost. In either case, the disadvantage is that the benchmark may be set too low or too high relative to the actual allowance price. For example, if it is set too high, this could induce more scrubbing at a higher cost than purchasing allowances. Conversely, if the benchmark is set too low, then opportunities to sell allowances, and reduce overall compliance cost, may be missed. For this reason, it is important that these means be viewed as temporary. As the market develops, a shift to actual market prices could take place. This could "seed" the market and foster its development by encouraging utilities to use the allowance market. This would require some early cooperation between the commission and its jurisdictional utilities to determine a fair estimate of the market value or control costs. The long-term benefit to ratepayers of a successful trading system could be worth the risk and effort.

This method explicitly recognizes that the allowances are valuable assets to the utility and others and that neither the utility or ratepayers should be the sole beneficiary of the CAAA's creation of this new asset. It also allows flexibility to the commission in determining explicitly what portion of the new asset's value should accrue to the utility and what should accrue to ratepayers (of course, this could be achieved under a traditional approach as well). The purpose of allowing the utility an eventual return on the initial allowances is so the utility will not have a preference for large capital expenditures or purchased allowances over those initially allocated at zero (assuming that purchased allowances are allowed into rate base at the market price). While this method may not eliminate all distortions in the ratemaking process, it does remove the bias from options involving allowance transactions and gives the utility an incentive to act in the best interest of ratepayers.

A commission adopting this method must then decide: (1) the fair market price for the allowances, (2) the portion of beneficial ownership of allowances belonging to ratepayers and shareholders (as in Chapter 8), (3) the number of years that the utility will be allowed to use the determined ratepayers' allowances, (4) the discount rate for the NPV calculation for the purchase of the asset from ratepayers, and (5) what portion of the gain the utility should be allowed to retain and what should be returned to ratepayers.

Accounting Treatment of Allowances and Compliance Costs: FERC Proposed Changes to the Uniform Systems of Accounts

FERC has issued a Notice of Proposed Rulemaking[8] (NOPR) to revise the Uniform Systems of Accounts (USOA) to account for allowances, compliance costs, other "regulatory-created" assets and liabilities, and amend FERC form numbers 1, 1-F, 2, and 2-A. A stated objective of the NOPR is to achieve rate neutrality by not dictating or suggesting a specific ratemaking treatment to state commissions or FERC. The NOPR states that it "does not bar regulatory commissions (including [FERC]) from adopting any particular ratemaking treatment."

The FERC believes that the allowance program of Title IV of the CAAA is sufficiently novel to warrant revising the USOA and FERC's utility reporting requirements. Also, the Commission points out that there are a number of possible alternative accounting approaches that could be adopted by utilities and state public utility commissions. The FERC NOPR, therefore, proposes revisions to the USOA to provide "guidance, uniformity and consistency in accounting and reporting for the allowances." The changes pertain to the classification, valuation, expense recognition, sale or other disposition, and reporting of allowances.

Account Classification

The Commission wants a classification of allowances that best reflects the nature of the allowances and promotes uniformity of accounting practices. FERC proposes to create two new inventory accounts for allowances: Account 158.1 Allowance Inventory, and Account 158.2 Allowances Withheld. These accounts would be included in "Current and Accrued Assets" section of the balance sheet.

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[8] Federal Energy Regulatory Commission, 18 CFR Parts 101, 141, 201, and 260, Docket Number RM92-1-000, "Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and Form Nos. 1, 1-F, 2 and 2-A," Issued December 2, 1991.

The Commission believes that there is no need to separately identify which allowances are used because a utility can generally use any eligible allowance to comply with the CAAA. Rather, the Commission contends the allowance inventory need only be reduced by the number of allowances used times the unit inventory cost for each allowance. Also, according to the Commission, this type of inventory accounting is appropriate since allowances are not subject to depreciation or amortization as are long-lived assets (such as utility plant) used in the production process over a number of periods. It is their belief that "[t]he data derived from [this] inventory accounting approach will give utility regulators meaningful information that may be useful in ratemaking or other regulatory determinations." In this approach, the accounting records would not and could not associate specific allowances with the specific compliance strategy adopted by the utility. Therefore, these account classifications would "not suggest or dictate any particular ratemaking treatment for the allowances and would therefore be consistent with the Commission's stated objective of being 'rate-neutral'."

<u>Measuring the Value of Allowances</u>

For measuring the value of allowances FERC proposes that utilities use a historical cost basis. The NOPR states that historical cost is the generally accepted measure of the value of intangible assets, such as franchises, patents, trademarks and other rights. They argue that "[h]istorical cost is readily ascertainable and verifiable, free from bias and useful to regulators, investors and other users of a utility's financial statements." Under this method allowances received from EPA at no cost to the recipient would be recorded at zero cost, while purchased allowances would be recorded at their historical exchange price. Original cost, conversely, would require the originally allocated allowances to be recorded as zero even after a sale to another party. FERC points out that this type of arrangement may discourage the development of the allowance market and would not provide regulators with relevant information on the cost of traded allowances. Some limitations to this method are discussed at the end of this section.

The Commission also provides a proposal for dealing with affiliated transactions. In this case the Commission proposes that allowances acquired from an affiliated company should be recorded by the acquiring company at the inventory cost of the affiliated entity that first obtained the allowance. The Commission bases this decision on the fact that affiliated companies cannot be presumed to be dealing at arm's length, and therefore these affiliated trades should not be presumed to be competitive, free-market dealings. Under this proposal, when a utility acquires allowances from an affiliate at a value other than the affiliated company's historical cost, the difference would be recognized as an equity contribution between affiliates.

The Commission proposes using the fair market value of allowances as the historical cost basis for allowances that are acquired as part of a "package" with equipment, fuel, or electricity. For determining the value of a stream of allowances, FERC proposes the use of the interest rate on a ten-year government bond.

FERC is also proposing accounting instructions to allow for possible allowance futures transactions by utilities. Their proposal would require utilities to defer the costs or benefits from hedging transactions and include these values in inventory when the related allowances are acquired or sold. FERC believes that allowance transactions entered into for speculation should not affect inventory pricing, since they do not relate to utility operations.

The Commission's NOPR proposes a method for utilities to account for allowances received in exchange for something other than a monetary payment. FERC is proposing that these transactions be based on the recorded inventory value of the allowances relinquished and the value of the "boot" (the dollars and/or asset(s) exchanged in a transaction). When a utility gives up boot in an allowance transaction, FERC proposes that the recordable cost of the newly-acquired allowances be the monetary equivalent paid in boot (for example, the fair market value of the asset surrendered) for the newly acquired allowances. For the utility giving up the allowance, the value would be based on the sum of the inventory cost of the allowances given up.

Inventory Methods for Allowances

FERC is concerned that since allowances are identical and interchangeable, a specific identification inventory method would allow management too much discretion in determining income and inventory balances by choosing particular allowances for use or sale. For this reason, the Commission believes that rather than a specific identification method, a weighted average cost method for allowance inventories should be used. The Commission argues that this method would provide "a rational, systematic, and objective measure of the cost of allowances used or sold during a period and would mitigate the effect of price changes on income and inventory balances." The Commission proposes that allowances in inventory be "vintaged" rather than grouped together in a single inventory. Under this approach, allowances eligible for use during the current year (including banked allowances from prior years) would be included in the determination of the weighted average cost of the vintage.

Since utilities will need to account for allocated allowances that are withheld by EPA for sale or auction, the Commission is proposing a separate, but parallel, inventory account. This would be Account 158.2, Allowances Withheld, and would be used to record the acquisition cost of allowances owned by the utility but withheld by EPA.

Expense Recognition of Allowances

The Commission believes that when allowances are used to comply with the CAAA, their inventory cost should be charged as an expense. The Commission proposes to require expense recognition of allowances on a monthly basis. Utilities would be required to charge allowances (including fractional amounts) to expense in the month in which the related sulfur dioxide emissions occurred. If a utility incurs a fine or penalty as a result of noncompliance with the CAAA, the USOA already requires that such a fine or penalty be charged to Account 426.3, Penalties.

The Commission also proposes classifying the expense account to record the expired cost of the allowances as a power production operating cost. The Commission would create a new expense account for allowances, Account 509, Allowances, and include the cost of allowances used with the production cost of steam for electric generation. Utilities could then seek authorization to recover the cost of allowances through their base rates or fuel adjustment clause, or some other appropriate manner.

The Commission proposes a two-step process for accounting for gains and losses on the sale, exchange, or other disposition of allowances. The first step would be to recognize the gain or loss in income. Upon the sale of allowances, a gain or loss would be recognized for the difference between the net proceeds received for the allowances and their inventory value. Any gain would be recorded in new Account 411.8, Gains from Disposition of Allowances, and any loss would be recorded in new Account 411.9, Losses from Disposition of Allowances. Income taxes associated with the gain or loss would be recorded in the appropriate utility operating income tax accounts. The second step would be to recognize the economic effects of actions taken, or expected to be taken, by regulators in their ratemaking treatment of the gain or loss on the disposition of allowances through the use of new generic accounts for regulatory-created liabilities and assets. These are: Account 182.3, Other Regulatory Assets; Account 244, Other Regulatory Liabilities; Account 407.3, Regulatory Debits; and Account 407.4, Regulatory Credits.

Regulatory-Created Assets and Liabilities

The Commission is proposing additional changes to the USOA to produce financial statements that are more descriptive and informative regarding the economic effects of the ratemaking process. In addition to accounting for allowance transactions, the Commission provides other examples of the need for change to the USOA, such as plant phase-in, normalization of significant nonrecurring operating or maintenance expenses, and gains and losses on the sale of assets.

FERC is proposing that the new Account 182.3, Other Regulatory Assets, include costs incurred and charged as an expense that have been, or are soon expected to be, authorized for recovery through rates, and which are not specifically provided for in other accounts. The regulatory-created assets would be recorded as charges to Account 182.3 and as a credit to new Account 407.4, Regulatory Credits. Account 182.3 would be amortized to new Account 407.3, Regulatory Debits, over the appropriate rate recovery period. If rate recovery is disallowed, the amount in Account 182.3 would be written off.

The proposed new Account 244, Other Regulatory Liabilities would include liabilities imposed by the ratemaking actions of regulatory agencies that are not specifically provided for in other accounts. Included in Account 244 would be revenues or gains realized and credited to income that the company is required, or is expected to be required, to use to reduce future rates. The regulatory-created liabilities would be established by credits to Account 244 and debits to new Account 407.3. The amount in Account 244 would be amortized to Account 407.4 over the appropriate period. If it is determined that the amount recorded in Account 244 will no longer be used to reduce future rates, then the remaining amount should be removed from the account.

Application of the FERC Proposal

There appears to be at least one limitation to the FERC's proposal. Specifically, with respect to the proposed use of a historical cost accounting basis for allowance valuation, there appears to be some confusion in the NOPR between "value" and cost. Recording the originally allocated allowances for accounting purposes at zero (the historical cost) while reflecting their cost, does not reflect their value to the utility or ratepayers. The accounting records should, some maintain, reflect their value as assets to the firm.

Moreover, there is the possibility that this accounting treatment could be translated to the ratemaking treatment of allowances. For the reasons discussed above, this would not necessarily be in the ratepayers' interest. It is important, therefore, that the ratemaking be determined first, then the accounting designed to reflect this treatment. There appears to be sufficient flexibility for states (and FERC) first to determine a ratemaking treatment separately and then determine an accounting treatment. The incentive ratemaking treatment proposed above, for example, could use the "Other Regulatory Assets" and "Other Regulatory Liabilities" accounts proposed by FERC. However, this would be somewhat cumbersome to implement and could result in accounting records difficult to decipher.

Most likely, the traditional and incentive ratemaking approaches described above would require different accounting treatments. Both can be applied, however awkwardly, within this proposed framework. This flexibility, of course, is an advantage to the FERC proposal.

CHAPTER 10

SUMMARY AND CONCLUSIONS

While EPA has the primary administrative role in implementing Title IV of the CAAA, the state public utility commissions and FERC are probably the most important single actors in determining the development and success of an allowance market. The policies and actions they adopt with regard to their jurisdictional utilities to implement the CAAA will profoundly influence the cost of compliance and the extent the market is used by utilities. Estimates of the cost of implementing Title IV with command-and-control measures alone put the cost 50 to 75 percent higher than with the allowance trading system created by the amendment.[1] As noted, estimates of this potential savings vary from $1 billion to $3 billion annually. Since commissions will have, and in some cases already have had, considerable influence on electric utility compliance decisions, their policies and actions will determine how successful allowance trading will be and, therefore, how much of this projected savings is actually realized.

The CAAA is silent on the type of policies that commissions should adopt to implement the amendments. Title IV of the CAAA states that "[n]othing in this section shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges. . .." It has been left to each state and FERC to implement the CAAA as they consider appropriate. While the CAAA does not directly mandate commissions to alter their regulatory procedures, the novelty of the allowance system makes it probable that changes will have to be made. The most significant of these changes will likely be development of rules and procedures to accommodate the allowances and the ratemaking treatment of the costs the utility incurs to comply with the CAAA.

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[1] Paul R. Portney, "Economics and the Clean Air Act," *The Journal of Economic Perspectives* 4 no. 4 (Fall 1990): 173-181.

One consequence of an allowance trading system is that the number of options available to utilities is greatly expanded over that of command-and-control environmental regulation. In this sense, trading is a two-edged sword bringing opportunity and choice while increasing uncertainty, since under command and control utilities simply are told the required reduction and technology. The allowance trading system should not, however, be thought of as just a burden to be borne or an obstacle to be overcome, but as an opportunity for utilities and commissions to get the same level of reduction in SO_2 emissions for a lower cost than command and control. The question for state commissions and FERC becomes how to manage this uncertainty while taking advantage of this new opportunity.

Since the actions of the state commissions and FERC will greatly affect the allowance market's development, commissions may consider facilitating the allowance market's development, or at least try to avoid actions that may impede it. While individual commissions may not regard the development and success of an allowance market as their responsibility, ratepayers likely will benefit if it does develop successfully. If states adopt policies in the long-term interest of their ratepayers, then an allowance market will likely develop allowing at least some of the predicted savings to be realized. When one considers that the federal objective is to see that the market develops and is successful and that the state objective is to comply with the CAAA at least cost, then the result is that federal and state objectives are coincident.

Three significant policy questions that commissions will need to consider and resolve are: who are the beneficial owners of the allowances, what are the incentives provided to the utility from the ratemaking treatment of compliance costs and allowances, and, how should the commissions manage the uncertainty associated with compliance planning?

Beneficial Ownership of Allowances

One of the more important issues for commissions to resolve is who are the beneficial owners of the allowances. While it is quite clear that Congress intended the legal title and ownership of emission allowances to be with the utility, the allocation of allowances--including bonus allowances--reflects an equity judgement by Congress. The allocation was not meant to be a give-away or subsidy, but was an effort to cushion rate shock related to the cost of acid rain compliance with the allowance trading system intended to lower the overall cost of acid rain compliance nationwide.

Regulated utilities have a fiduciary duty to act as trustees of the public, in particular of ratepayers, under the regulatory compact. Because of this, ratepayers will often be considered the beneficial owners of the allowances while the utilities are the legal owners of the allowances.

As a result, the benefit resulting from the regulatory compact (or, stated another way, the fiduciary duty of the utility that benefits the customers) is the ability of the utility to use its allowances to lower its cost of compliance. The fiduciary duty of the utility to engage in compliance planning and allowance trading is consistent with its overall obligation to provide reliable service to customers at the lowest reasonable cost. In return, the public utility receives an opportunity to recover its prudently incurred expenditures and to earn a reasonable return on its prudently incurred investment. As beneficial owners to the emission allowances, ratepayers are third-party beneficiaries to any sale or use of the allowances.

Since the initial allocation of allowances is associated with a particular affected unit, a commission could examine the proportion to which the plant is depreciated to determine how much of the beneficial ownership of the allowances "belongs" to the utility and how much is the ratepayers'. One would expect that most of this beneficial ownership would be found to accrue to the ratepayers because many of the underlying assets are older coal-fired plants likely to be fully depreciated. In this case, the beneficial ownership of the emission allowances associated with the fully depreciated plant would go entirely to ratepayers. The outcome of this determination will drive many subsequent decisions by commissions concerning compliance costs and allowances.

Ratemaking Treatment of Allowances

The ratemaking treatment of allowances is probably one of the most difficult and complex issues that commissions face with CAAA implementation. This is because the novelty of the allowance system means there is no exact analogy. Furthermore, the allowance system is to be integrated into an already complex system of state and federal regulation. Commissions are likely to begin by drawing upon previous experiences with similar assets and issues when determining a policy for CAAA compliance. This may include the regulatory treatment of the sale of assets (for example, financial, land, and so on), coal contracting and inventory, fuel price changes, and planning for future power supply (for example, integrated resource planning procedures).

Since there is no exact analogy for allowances, commissions should consider the particular qualities of allowances, including:

(1) that the original allocation of allowances will be obtained at no cost from the Environmental Protection Agency and are associated with specific units;

(2) that while the utility will have title to the allowances, because the utilities are regulated entities, beneficial ownership will, in many cases, reside with the ratepayers;

(3) that both allocated and purchased allowances will have some market value, although uncertain at this time; and

(4) that allowances will be required by many facilities that generate electricity and emit sulfur dioxide for the foreseeable future.

Commissions may also consider at least two features when developing their ratemaking policies that can be used as general guiding principles. First, that the reward or penalty from compliance planning decisions, including allowance trading, should be commensurate with the party taking the risk. That is, the ratemaking treatment should be symmetrical with respect to gains and losses. While it may appear obvious that the risk taker should receive the reward or penalty, with compliance planning who took the risks will not always be obvious.

A second matter for commissions to consider is that the ratemaking process itself could introduce biases toward particular compliance options, other than those in the long-term interest of ratepayers. This means that attempts should be made to develop a ratemaking treatment that makes it in the utility's self-interest to comply in a manner that is also in the interest of ratepayers. One method is to develop an incentive mechanism for the ratemaking treatment of allowances and compliance costs. This would minimize commission involvement in the details of compliance planning, relieving it of the burden of developing a ratemaking treatment that covers every contingency that could arise. Developing an incentive-based ratemaking process is itself a complex task, but well worth the effort. This is not only because it could lead to lower compliance costs, but because it also could perhaps be applied to other future emission trading programs (for example NO_x or CO_2). A three-step mechanism is described in Chapter 9 as an example of an incentive-based ratemaking approach.

Managing Uncertainty

Another important consideration for commissions is that utilities face two important uncertainties associated with complying with the CAAA. The first is the future price of allowances. Since passage of the CAAA, forecasts have varied considerably (the highest price is six times the lowest) and are regarded in general as unreliable. Since the compliance option chosen by the utility is highly dependent on the allowance price, commissions should consider policies that recognize and try to accommodate this uncertainty. These policies include allowing utilities to participate in an allowance pool and enter into a mix of contracting arrangements to manage this risk. These include long-term, spot, and futures contracts.

The second uncertainty faced by utilities is the post-investment prudence of a capital expenditure required to comply with the CAAA. In other words, will an investment made by a utility which appeared to be prudent at the time the decision was made be found by its commission in the future to be imprudent? To avoid this outcome and the harm that can be caused by the fear of it, some have proposed that preapproving compliance plans, expenditures, or both be done to minimize the chance of this occurring. The goal is to manage the uncertainty associated with allowance trading and compliance decisions by not holding the utility responsible for factors that are beyond its control. As discussed in Chapter 6, there are several significant problems associated with this type of procedure.

Alternatively, to minimize their market risk, utilities should be allowed by their commissions to enter into agreements as a buyer or seller in the long-term, spot, forward, and futures markets (as hedgers), or all three, and in the EPA auction. If the risk, however, is shifted away from the utility toward ratepayers, then there is little incentive for the utility to manage its risk with these actions. Commissions may want to reserve their prerogative to conduct retrospective reviews of the contracts and other actions by the utility. Ideally, the responsibility should be the utility's to develop its own compliance and risk management strategy and be able to back up its assumptions and assertions if required. In exchange for this responsibility, the utility should be allowed to benefit from good decisions.

There are other means, besides preapproval, available to commissions to reduce regulatory risk. One is to make future regulatory actions predictable. While there have been several proposals for preapproval of compliance plans, expenditures, or both a reasonable degree of predictability (concerning the ratemaking treatment of compliance cost, for example) is all that is required to enable a utility to anticipate commission actions. These actions then can be considered by the utility when examining the various compliance options it faces. It is appropriate for utilities to ask for and expect clear and relevant guidelines from their commissions on ratemaking treatment of allowances and compliance expenditures.

It is important that these guidelines include the procedures and standards that will be used in future prudence reviews of compliance decisions. It is also important that this prudence standard be consistent with the way it was originally envisioned, principally, with no hindsight or "Monday morning quarterbacking." Without this standard, the cost of a retrospective review could be as much or more than the cost of a preapproval process. The possibility of a retrospective review is useful because it is a strong incentive to the utility to control its costs. To some extent, an incentive type of ratemaking system for allowances, such as the one discussed in Chapter 9, requires that these guidelines be predictable and credible to the utility. After all, the utility must have assurances that the "rules of the game" will not change once decisions have been made. Also, to be consistent with providing an incentive to the utility for good decisions, the utility should bear the market risk associated with compliance planning. The market risk should not be shifted to ratepayers (as preapproval does) and then allow the utility a share of any gain from allowance sales. In other words, the ratemaking treatment should be symmetrical with respect to the risks and rewards.

Preapproval actually may hinder the allowance market's development since there would be little incentive to minimize cost and use innovative compliance strategies such as allowance transactions. Commissions can, of course, require trading as part of an approved plan. However, forced allowance trading for the sake of trading will not necessarily lead to economic trading. Commission policy instead should be focused more on policies that provide the utility an incentive to seek an innovative and flexible compliance strategy. The utility typically knows its system and capabilities better than the commission and can, therefore, develop a more effective strategy--if provided the proper incentives. A self-regulating mechanism that gives the utility an incentive to comply at the least-cost will both lead to more economical trading decisions by the utility and benefit ratepayers in the long run.

Designing General Regulatory Guidelines

These three issues, beneficial ownership of allowances, incentives from ratemaking treatment, and managing uncertainty, fit together to form more general policy guidelines. From this discussion it is clear that commissions can take several actions to ensure that their jurisdictional electric utilities make decisions in the long-term interest of ratepayers, while at the same time foster the development of an allowance market. One action is to develop clear and credible regulatory guidelines that include the specific ratemaking treatment of the initially allocated allowances; purchased, sold, and banked allowances; and capital and fuel expenditures made for CAAA compliance. Developing guidelines can reduce the regulatory uncertainty associated with the utility's compliance decisions. These guidelines should be developed in advance by the commission and should provide sufficient detail so the utility can predict, with a reasonable degree of reliability, regulatory outcomes when conducting compliance planning.

When developing these guidelines states may consider that a market is more likely to develop if states adopt policies that encourage economical trading and banking of allowances, and that encourage utilities to choose the lowest-cost compliance option. Commissions should consider carefully the incentives a utility receives and the consequences of the commission's actions on its compliance choice. While the effect of commission action on the emerging allowance market may not concern the individual commission, commission policies that give utilities an incentive to comply with the CAAA in a least-cost manner, mean the allowance market likely will develop and generate the predicted savings.

Three overall policy elements should be considered for these policy guidelines. First, as noted, they should provide the utility with a reasonable degree of predictability. The description of the regulatory treatment should be sufficiently detailed so the utility in making its compliance decisions can reasonably predict what the regulatory treatment will be. Again, this treatment need not necessarily include a preapproval of a specific compliance plan. Commissions may need to preserve a process of retrospectively reviewing compliance decisions since these procedures were developed, in part, to alleviate the lack of incentive the utility has to minimize costs under cost-based regulation.

Second, the guidelines should allow utilities flexibility in choosing compliance options. By allowing flexibility, the commission increases the number of compliance options considered by the utility and permits the utility to seek feasible and innovative alternatives, including buying and selling allowances. Other possible options include repowering, redispatching existing units, purchasing power from others, switching to lower sulfur coal, installing scrubbers, adopting innovative clean coal technologies, and pursuing conservation to reduce demand. The guidelines themselves should be somewhat flexible since there has been no previous experience with a trading system on this scale and since no commission has had to deal with a similar asset. For this reason, it is likely that changes to the guidelines will be required over time.

Third, and perhaps most important, commissions can adopt a ratemaking treatment that provides the utility with an incentive to minimize its net compliance cost. The treatment can be structured in such a way that the commission's involvement in the actual compliance decisions of the utility is minimized. The primary goal is to minimize the cost of compliance to ratepayers by providing the utility with an incentive to minimize its own costs. This will help ensure that the utility makes decisions in the long-term interest of ratepayers that, again, has the incidental effect of fostering the allowance market.

The common elements of a ratemaking treatment designed to minimize the cost of compliance to ratepayers include flexibility, predictability, a lack of bias, and symmetry in the treatment of risk and gains or losses. While these features alone do not guarantee that the allowance market will succeed, they are a start. When Congress established a market-based allowance system to limit SO_2 emissions in the CAAA, it created a new asset. The national allowance market, if it develops successfully, will determine these allowances' prices or values and the cost of compliance to ratepayers. State commissions and the FERC will be determining the value of the allowances for ratemaking purposes and sending signals to their jurisdictional utilities on how to comply. While the individual commissions may not regard the development and success of an allowance market as their responsibility, it is clear that the market's fate is in their hands. From the perspective of individual commissions, creation of the allowance market provides an opportunity for utilities to comply with federal pollution control standards at a lower cost than previous environmental regulation.

APPENDIX A

UTILITY COMPANY SHARES OF EMISSION ALLOWANCES

TABLE A-1

20 LARGEST COMPANY SHARES OF PHASE I EMISSION ALLOWANCES

Utility Name	Phase I Allowances	Share of Total (%)
Georgia Power Company	581,600	10.2
Tennessee Valley Authority	552,640	9.7
Ohio Power Company	432,050	7.6
Public Service Company of Indiana	320,668	5.6
Monongahela Power Company	231,060	4.1
Union Electric Company	200,330	3.5
Ohio Edison Company	177,626	3.1
Illinois Power Company	175,938	3.1
Pennsylvania Electric Company	175,170	3.1
Pennsylvania Power & Light Company	158,370	2.8
Cleveland Electric Illuminating Company	150,763	2.6
West Pennsylvania Power Company	145,260	2.5
Alabama Power Company	134,070	2.4
Virginia Electric & Power Company	121,730	2.1
Indiana-Kentucky Electric Corporation	120,190	2.1
Potomac Electric Power Company	119,980	2.1
Indianapolis Power & Light Company	97,768	1.7
Long Island Lighting Company	93,200	1.6
Ohio Valley Electric Corporation	93,200	1.6
Cincinnati Gas & Electric Company	93,018	1.6
Total Top 20	4,174,631	73.1

Source: Unpublished 1991 EPA, Acid Rain Division data and authors' computations.

TABLE A-2

TOP 17 HOLDING COMPANY SHARES OF PHASE I EMISSION ALLOWANCES

Top 17 Holding Companies	Phase I Allowances	Share of Total (%)
Southern Company	821,160	14.4
American Electric Power	557,717	9.8
Allegheny Power System Incorporated	376,320	6.6
General Public Utilities Corporation	191,340	3.4
Centerior Energy Corporation	150,763	2.6
Dominion Resources Incorporated	121,730	2.1
IPALCO Enterprises Incorporated	97,768	1.7
TECO Energy Incorporated	82,250	1.4
Wisconsin Energy Corporation	75,730	1.3
CIPSCO Incorporated	75,725	1.3
NIPSCO Industries Incorporated	56,428	1.0
CMS Energy Corporation	42,340	0.7
DQE	39,170	0.7
WPL Holdings Incorporated	37,440	0.7
Atlantic Energy Incorporated	20,780	0.4
Iowa Southern Incorporated	10,710	0.2
IE Industries Incorporated	8,180	0.1
Total Top 17	2,765,551	48.4

Source: Unpublished 1991 EPA, Acid Rain Division data and authors' computations.

TABLE A-3

TOP 20 NONAFFILIATE COMPANY SHARES OF PHASE I EMISSION ALLOWANCES

Top 20 Nonaffiliate Companies	Phase I Allowances	Share of Total (%)
Tennessee Valley Authority	552,640	9.7
Public Services Company of Indiana	320,668	5.6
Union Electric Company	200,330	3.5
Ohio Edison Company	177,626	3.1
Illinois Power Company	175,938	3.1
Pennsylvania Power & Light Company	158,370	2.8
Indiana-Kentucky Electric Corporation	120,190	2.1
Potomac Electric Power Company	119,980	2.1
Long Island Lighting Company	93,200	1.6
Ohio Valley Electric Corporation	93,200	1.6
Cincinnati Gas & Electric Company	93,018	1.6
Associated Electric Cooperative Inc.	90,360	1.6
Cardinal Operating Company	81,726	1.4
Kentucky Utilities Company	80,350	1.4
Commonwealth Edison Company	73,563	1.3
Electric Energy Incorporated	69,030	1.2
Big Rivers Electric Corporation	62,080	1.1
Southern Indiana Gas & Electric Company	54,312	1.0
East Kentucky Power Cooperative Inc.	45,550	0.8
Public Service Company of New Hampshire	32,190	0.6
Total Top 20	2,694,321	47.2

Source: Unpublished 1991 EPA, Acid Rain Division data and authors' computations.

TABLE A-4

20 LARGEST COMPANY SHARES OF PHASE II EMISSION ALLOWANCES

Utility Name	Phase II Allowances	Share of Total (%)
Tennessee Valley Authority	459,401	5.5
Georgia Power Company	384,015	4.6
Texas Utilities Generating Company	268,861	3.2
Detroit Edison Company	227,061	2.7
Pennsylvania Electric Company	222,996	2.6
Alabama Power Company	216,348	2.6
PacifiCorp	201,305	2.4
Ohio Power Company	191,971	2.3
Appalachian Power Company	178,062	2.1
Pennsylvania Power & Light Company	171,150	2.0
Duke Power Company	151,748	1.8
Public Services Company of Indiana	149,491	1.8
Carolina Power & Light Company	145,611	1.7
Virginia Electric & Power Company	145,143	1.7
Monongahela Power Company	142,806	1.7
Commonwealth Edison Company	136,477	1.6
Union Electric Company	134,946	1.6
Florida Power Corporation	118,310	1.4
Ohio Edison Company	109,213	1.3
Dayton Power & Light Company	107,362	1.3
Total Top 20	3,862,277	45.9

Source: Unpublished 1991 EPA, Acid Rain Division data and authors' computations.

TABLE A-5

TOP 20 HOLDING COMPANY SHARES OF PHASE II EMISSION ALLOWANCES

Top 20 Holding Companies	Phase II Allowances	Share of Total (%)
Southern Company	712,792	8.5
American Electric Power	503,796	6.0
Texas Utilities Electric Company	268,861	3.2
General Public Utilities Corporation	238,461	2.8
Allegheny Power System Incorporated	217,946	2.6
Dominion Resources Incorporated	145,143	1.7
Central and South West Corporation	131,387	1.6
Florida Progress Corporation	118,310	1.4
Centerior Energy Corporation	110,873	1.3
DPL Incorporated	107,362	1.3
CMS Energy Corporation	106,989	1.3
Houston Industries Incorporated	88,840	1.1
Wisconsin Energy Corporation	88,711	1.1
TECO Energy Incorporated	82,491	1.0
Entergy Corporation	73,551	0.9
IPALCO Enterprises Incorporated	73,283	0.9
FPL Group Incorporated	66,885	0.8
SCANA Corporation	63,808	0.8
CIPSCO Incorporated	63,751	0.8
Pinnacle West Capital Corporation	60,496	0.7
Total Top 20	3,323,736	39.8

Source: Unpublished 1991 EPA, Acid Rain Division data and authors' computations.

TABLE A-6

TOP 20 NONAFFILIATE COMPANY SHARES OF PHASE II EMISSION ALLOWANCES

Top 20 Nonaffiliate Companies	Phase II Allowances	Share of Total (%)
Tennessee Valley Authority	459,401	5.5
Detroit Edison Company	227,061	2.7
PacifiCorp	201,305	2.4
Pennsylvania Power & Light Company	171,150	2.0
Duke Power Company	151,748	1.8
Public Services Company of Indiana	149,491	1.8
Carolina Power & Light Company	145,611	1.7
Commonwealth Edison Company	136,477	1.6
Union Electric Company	134,946	1.6
Ohio Edison Company	109,213	1.3
Potomac Electric Power Company	101,585	1.2
Illinois Power Company	101,410	1.2
Salt River Project	91,554	1.1
Cincinnati Gas & Electric Company	86,243	1.0
New England Power Company	79,186	0.9
Kansas City Power & Light Company	78,517	0.9
Kentucky Utilities Company	77,756	0.9
Kansas Power & Light Company	63,337	0.8
Associated Electric Cooperative Inc.	59,153	0.7
Niagara Mohawk Power Corporation	59,139	0.7
Total Top 20	2,684,283	31.8

Source: Unpublished 1991 EPA, Acid Rain Division data and authors' computations.

APPENDIX B

SYNOPSIS OF THE MONTGOMERY MODEL

Consider a geographical region or airshed in which there are k stationary sources of a single air pollutant. Of these, $n \leq k$ are producers of a single product (say, electricity) who may behave strategically toward each other in their common output market. Distributed about the region are m receptor sites. Environmental quality in the region is defined and regulated according to the level of pollutant concentration at each of these sites. Associated with each firm i is a vector $d_i = (d_{i1},...,d_{im})$ which specifies the dispersion of pollutant to each of the m sites that results when firm i emits one unit of the pollutant.

Suppose the environmental authority specifies $Q^* = (q_1^*,...,q_m^*)$, a vector of the maximum allowable pollutant concentrations at each receptor. Let the yearly emissions level of firm i be given by e_i; let $E = (e_1,...,e_k)$. Then if we let $D = [d_1,...,d_k]$ be an $m \times k$ matrix of dispersion coefficients, the quality standards are met if $ED \leq Q^*$, where vectors are understood to be conformable and oriented so that the given operations are well defined. This constraint on the system may be applied to the planner's problem; any potential trading solution that violates it is not allowed.

Montgomery's[1] formulation is similar to this one. He proceeds by exploiting the perfect competition assumption, using an envelope result to reduce the emitter's problem to one of minimizing the cost of reducing emissions to the maximum allowed level. If emitters always choose output production levels optimally for a given e_i, and if the price they receive for the output is fixed, the objective function of a polluting firm may be written as an implicit cost function. The firm chooses its output level so as to minimize this cost, and in doing so it also maximizes its profits. Write the cost of abating pollution emissions from the optimal unconstrained level to the legally specified level as $C_i(e_i)$,

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[1] David W. Montgomery, "Market in Licenses and Efficient Pollution Control Programs," *Journal of Economic Theory* (1972): 395-418.

where, again, the cost of production is suppressed. Then the regulatory authority, in choosing a CAC system that specifies e_i for each firm, minimizes the cost of achieving air quality Q^* by solving the following program

$$\text{(1)} \qquad \min_{e_1,\ldots,e_k} \sum_{i=1}^{k} C_i(e_i) \qquad \text{s.t.} \quad ED \leq Q^*, \quad 0 \leq E.$$

The solution to this program, as demonstrated by Montgomery and others, has desirable efficiency properties under suitable conditions.

The formal mathematical models that underlie this logic can be presented in a fairly simple form. Here, a numerical example that gives the flavor of the argument should prove helpful. It should be kept in mind that this version is quite simple. Nevertheless, the logic is the same as in the more elaborate versions that are to be found in the literature. It is also akin to those versions in the way that it relies upon a set of simplifying assumptions that makes the market perfect in the economist's sense: everyone knows everything, nobody has any market power, and so on.

Consider a world in which two coal-burning plant supply all of the electricity. These plants (call them plant 1 and plant 2) are located near each other, and each emits a certain amount of sulfur dioxide into the air for every unit of coal it burns. Imagine that the world is now in equilibrium, that together these plants exactly meet the demand for electricity, that they know everything that can be known about each other, about tomorrow's weather, and so on. Suppose also that utility regulation has not yet arrived, so that neither plant is concerned with whether its decisions will be approved in an upcoming hearing. Finally, suppose that plant 1 is currently emitting 100 tons of SO_2 annually, and that plant 2 is emitting 150 tons (for a total level of emissions of 250 tons).

We must make another assumption about the plants' behavior: for a given level of electricity generation, and for a given level of sulfur emissions, each plant gets everything else right. That is, all of the usual optimizing behavior (employing the right number of people, burning the optimal amount of coal, building a plant of exactly the right size, and so on) is taking place. No mistakes are being made anywhere. This assumption is critical because it allows us to put all but one of the plant's decisions in the background, and to write an *abatement cost function* that purports to represent everything interesting about the plant's operations. This function gives the cost of doing business, but in such a way that cost depends only upon the level of SO_2 emissions. What's more, this function is such that for a given level of generation, costs will *increase* as emissions *decrease*. This is so because in order to produce at the same level as emissions go down, more must be spent on abatement equipment, and so on.

In this example, plant 1 is a relatively new unit, so that its level of emissions is lower than that of plant 2, and it is also cheaper for plant 1 to abate. Let's say that sulfur emissions of plant 1 are represented by e_1, and those of plant 2 by e_2. The abatement cost functions for the two plants are assumed to be given by

$$C_1(e_1) = \frac{5{,}000}{\sqrt{e_1}} \quad \wedge \quad C_2(e_2) = \frac{40{,}000}{\sqrt{e_2}} \ .$$

In the world as it exists here, then, with plant 1 emitting 100 tons ($e_1 = 100$) at a cost of \$500 and with plant 2 emitting 150 tons at a cost of \$3,266, total costs for the industry equal \$3,766.

The example includes one additional actor: an environmental regulator. This benevolent government employee, charged with protecting the environment, decides that the annual level of emissions should be reduced by 40 percent to 150 tons. This number is made the law of the land, and the regulator is charged with devising a plan for meeting the new environmental objective. One of two alternatives for achieving the required 100 tons of abatement may be selected.

The first is a simple version of a command-and-control regime: each plant will be required to cut back in proportion to its initial pollution level. This is the proportional reduction (PR) plan. The second is to implement a marketable pollution permit scheme, whereby the two plants are given a total of 150 allowances (how these are divided between them may or may not concern our regulator), each granting its holder the right to emit a ton of sulfur dioxide. This is the tradable allowance (TA) plan. Under TA it is illegal to emit more sulfur than represented by the allowances a plant holds. With this program the two plants have the freedom to reach an agreement among themselves---free, in particular, from further government intervention---about how much each plant should pollute. Whatever the initial allocation of allowances, the two plants buy and sell allowances from one another so that each owns exactly enough to emit according to its optimal plan.

Now the setup is complete. The regulatory decision about which plan to implement is based only upon total cost considerations. Whichever plan is cheaper for the industry will be chosen. The results of the relevant calculations appear in Table B-1. Without pollution regulation, the numbers are as above (total cost equals \$3,766). These appear in the first column of the table. The PR plan is easy to implement, and requires very little in the way of calculation. Each plant must come up with a reduction of 40 percent, so that plant 1 winds up emitting $e_1 = 60$ tons, and plant 2 emits $e_2 = 90$ tons. The corresponding costs are $C_1 = \$645.50$ and $C_2 = \$4,216.40$ (recall that costs go up as emission levels fall). The total cost is \$4,861.90.

Under the TA plan, each plant sets the marginal cost of abatement equal to the allowance price. Trade between the two plants will occur in such a way as to equalize this marginal cost across the plants. In order to decide which plan to implement, the regulator will want to calculate the optimal decision under this plan, and then to compare it to \$4,861.90. This involves minimizing the total cost of compliance (equalling the sum of the two cost functions), given that total emissions cannot exceed 150 tons. The cost-minimizing decision is for plant 1 to reduce the most, emitting a total of only 30

TABLE B-1

TOTAL OPERATING COSTS UNDER VARIOUS POLLUTION CONTROL REGIMES

	Status Quo	Proportional Reductions	Tradable Coupons
Plant 1 Emissions	100	60	30
Plant 2 Emissions	150	90	120
Total Emissions	250	150	150
Plant 1 Costs	$ 500	$ 645.50	$ 912.87
Plant 2 Costs	3,266	4,216.40	3,651.48
Total Costs	3,766	4,861.90	4,564.35
Coupon Price	n.a.	n.a.	$15.21

tons, and for plant 2 to emit 120 tons. The corresponding costs of operating (ignoring the purchase or sale of allowances) are $912.87 for plant 1 and $3,651.48 for plant 2. Total cost to the industry is $4,564.35. It is also relatively easy to calculate the market-clearing allowance price. This price, equaling the marginal abatement cost for both plants, will equal $15.21.

It is easy to see that the tradable allowance plan should be selected. Under this plan, total cost of compliance with the environmental standard is $297.55 less than under the proportional reduction plan. It is essential, in order fully to understand this example, to keep in mind exactly what goes wrong if the PR plan is implemented. Plant 2 abates at a relatively high cost, which means the resources devoted to pollution control when this plant is emitting only 90 tons are not used wisely. The same level of expenditures on abatement at plant 1 would have purchased a greater level of abatement. This is the source of the inefficiency and of the additional cost of the PR plan over the TA plan.

APPENDIX C

SURVEY RESPONSES: ELECTRIC UTILITY COMPLIANCE WITH THE CLEAN AIR ACT AMENDMENTS OF 1990

TABLE C-1

STATE PUCs: ACTIONS AND MAJOR ISSUES

State	Actions Undertaken Concerning Compliance	Contemplating Requirements That Might Limit Market?	What is the Most Important Issue in Implementation?
Alabama	Staff training Review plans	No	Interstate allowance trading
Arizona	Staff training	No	Incorporate into least-cost planning Ratemaking treatment of allowances Determine market value of allowances
Arkansas	No action	No	Allocation of subsidiaries' allowances
California	No response	No response	No response
Colorado	No action	No	No response
Connecticut	Staff training Sponsor workshop Develop policy Review plans	Not decided	Ratemaking treatment of allowances Impact on multistate holding companies Impact on power pool dispatch Impact on integrated resource planning
Delaware	Staff training	No	Treatment of trading gains/losses
District of Columbia	Staff training Review plans	No	Environmental impact of secondary waste
Florida	Staff training Develop policy Review plans	No	Treatment of trading gains/losses Prudence of compliance plans Allocation of special growth allowance
Georgia	Staff training	No	Not known
Idaho	Staff training	No	Not known

TABLE C-1--Continued

State	Actions Undertaken Concerning Compliance	Contemplating Requirements That Might Limit Market?	What is the Most Important Issue in Implementation?
Illinois	Staff training Sponsor workshop Develop policy	No	Treatment of old and purchased allowances Reform of fuel adjustment clause Establishment of risk-sharing mechanism
Indiana	Staff training Develop policy	No	"Optimal" compliance strategies Incorporation into least-cost planning Treatment of allowances Coordination with other regulators
Iowa	Staff training Review plans	No	Under determination
Kansas	No action	No	How to deal with new capacity needs
Kentucky	Review plans Initiate generic case	No	Least-cost planning versus coal mining economy Accounting and ratemaking for allowances Rate impact of compliance
Louisiana	No response	No response	No response
Maine	Staff training	No	Can afford to wait and see what others do
Maryland	Develop policy Review plans	No	Cost recovery for capital investment Cost allocation among ratepayers
Massachusetts	Other--open docket	No	Distribution of risk, cost, and benefit
Michigan	Staff training Develop policy Review plans	No	Best compliance strategy with low cost

TABLE C-1--Continued

State	Actions Undertaken Concerning Compliance	Contemplating Requirements That Might Limit Market?	What is the Most Important Issue in Implementation?
Minnesota	Sponsor workshop Review plans	No	Allocation of costs and benefits Valuation of allowances
Mississippi	Staff training Develop policy Review plans	No	Treatment of initial allowances Comparing strategies at utilities
Missouri	Review plans	No	Value of allowances
Montana	No action	No response	No response
Nebraska	No response	No response	No response
Nevada	No action	No	Bonus allowances for renewable energy
New Hampshire	No action	No	Compliance with phase I Ensuring least cost strategies
New Jersey	Staff training Review plans	No	Consistent with least-cost planning Proceeds from allowance trades
New Mexico	Staff training	No	Allocation of compliance costs
New York	Staff training Sponsor workshop	No	Not decided
North Carolina	No action	No	Prudence of purchases/sales of allowances
North Dakota	No action	No	Fuel-switching impact on mining economy Increased electric rates Allowances for future plants
Ohio	Staff training Sponsor workshop Review plans Develop policy	No	Distribution of compliance costs Impact on Ohio industries Impact on coal economy

TABLE C-1--Continued

State	Actions Undertaken Concerning Compliance	Contemplating Requirements That Might Limit Market?	What is the Most Important Issue in Implementation?
Oklahoma	No action	No	Treatment of emission trading
Oregon	Staff training	No	Valuing emission allowances Coordinating compliance and least-cost
Pennsylvania	Staff training Sponsor workshop Review plans Develop policy	No	CWIP Prudence review Allowance trading
Rhode Island	Sponsor workshop	No	Not decided
South Carolina	No action	No	No response
South Dakota	No action	No	Affected units in phase II
Tennessee	No response	No response	No response
Texas	Staff training Develop policy Review plans	No	Sufficient allowances for future growth
Utah	No action	No	How to take advantage of bonus allowance
Vermont	Staff training	No	Few interests in phase I or II sources
Virginia	Staff training Review plans	No	Reasonableness of costs Scrubbing versus switching
Washington	Staff training	No	Regulatory treatment of allowances Interjurisdictional issues
West Virginia	Review plans	No	Least-cost compliance strategies Least costs for power pools Assignment of costs to power pools

TABLE C-1--Continued

State	Actions Undertaken Concerning Compliance	Contemplating Requirements That Might Limit Market?	What is the Most Important Issue in Implementation?
Wisconsin	Staff training Develop policy Review plans	No	Integration with least-cost Market prices Flexibility
Wyoming	Staff training Review plans	Uncertain	Accounting for allowances and strategy Toxics 2000 compliance

TABLE C-2

STATE PUCs: NEW METHODS AND ALLOCATIONS

State	Will Implementation Require the Commission to Undertake New Methods or Activities?	Has the Commission Considered How Shareholders and Ratepayers Will be Allocated the Costs and Benefits of Compliance?
Alabama	Change preapproval process	Minor consideration given
Arizona	Develop allowance treatment Alter IRP process	No
Arkansas	No	No
California	No response	No response
Colorado	Change preapproval process Develop allowance treatment Alter IRP process	No
Connecticut	Change preapproval process Alter IRP process	No
Delaware	Develop allowance treatment	Pending PJM Power Pool actions
District of Columbia	Develop allowance treatment	No
Florida	Develop allowance treatment Change preapproval process	Staff report discussed issue
Georgia	Impact utility IRP filings	No action taken to date
Idaho	Not involved in phase I	No
Illinois	Change preapproval process Develop allowance treatment Alter IRP process Alter current prudence review	Yes, see earlier responses
Indiana	Change preapproval process Develop allowance treatment Alter IRP process Rolling prudence review	No

TABLE C-2--Continued

State	Will Implementation Require the Commission to Undertake New Methods or Activities?	Has the Commission Considered How Shareholders and Ratepayers Will be Allocated the Costs and Benefits of Compliance?
Iowa	Develop allowance treatment	No
Kansas	Develop allowance treatment Alter IRP process Change preapproval process	See previous answers
Kentucky	Alter IRP process	No formal consideration has been given
Louisiana	No response	No response
Maine	Develop allowance treatment Alter IRP process	No
Maryland	Develop allowance treatment Alter IRP process	Precedent for allocation among ratepayers and shareholders will be set in a current cost recovery/compliance case (the unit is not in Maryland)
Massachusetts	Externality treatment	Not yet addressed
Michigan	Slight modifications	Have begun considerations, but have made no decisions
Minnesota	Develop allowance treatment Change preapproval process	Established a work group to evaluate this and other CAAA compliance issues
Mississippi	Develop allowance treatment Change preapproval process	Preliminary stages of considering issue
Missouri	None anticipated at this time	Not at this time
Montana	No response	No response
Nebraska	No response	No response
Nevada	No response	No

TABLE C-2--Continued

State	Will Implementation Require the Commission to Undertake New Methods or Activities?	Has the Commission Considered How Shareholders and Ratepayers Will be Allocated the Costs and Benefits of Compliance?
New Hampshire	None anticipated at this time	No consideration yet
New Jersey	Develop allowance treatment	Informal consideration has begun, but no formal decision
New Mexico	Develop allowance treatment	No
New York	Too early to judge	Not yet
North Carolina	Unsure at this time	Not yet
North Dakota	Unsure at this time	No
Ohio	Change preapproval process Develop allowance treatment Alter IRP process Commission Ordered Investigations on allowance trading	Preliminary consideration only, but no final determination
Oklahoma	Develop allowance treatment Alter IRP process	No
Oregon	Develop allowance treatment Alter IRP process	No
Pennsylvania	No	Hearings have been completed on the West Penn Power (APS) Compliance filing
Rhode Island	Change preapproval process Develop allowance treatment Alter IRP process Alter prudence review procedure Alter rolling prudence review	No
South Carolina	Develop allowance treatment	No
South Dakota	Case-by-case basis examination	No

TABLE C-2--Continued

State	Will Implementation Require the Commission to Undertake New Methods or Activities?	Has the Commission Considered How Shareholders and Ratepayers Will be Allocated the Costs and Benefits of Compliance?
Tennessee	No response	No response
Texas	Develop allowance treatment Alter IRP process Alter prudence review procedure	No decisions made yet
Utah	Develop allowance treatment Alter IRP process	No formal deliberation yet
Vermont	Alter IRP process	No
Virginia	Develop allowance treatment	No
Washington	Develop allowance treatment	No
West Virginia	No response	No final determinations
Wisconsin	Change preapproval process Develop allowance treatment Alter IRP process	Preliminary belief is that ratepayers bear the costs and receive the benefits
Wyoming	Develop allowance treatment Alter IRP process	Informal consideration, no dockets or public discussions

TABLE C-3

STATE PUCs: TREATMENT OF ALLOWANCES AND MULTISTATE ISSUES

State	Has the Commission Decided How to Treat Costs and Revenues Related to SO_2 Emission Allowances for Setting Rates?	Does the Commission Anticipate Having to Address Multistate Issues? If So, Does It Plan to Coordinate with Other Commissions?
Alabama	Not at this time	Yes
Arizona	No	Probably, but no plans to coordinate yet
Arkansas	No	Yes, but decision hasn't been made to coordinate with other commissions
California	No response	No response
Colorado	No	Yes
Connecticut	No	Yes, plans are unclear at this time although a history of interstate coordination exists in New England
Delaware	No	Yes. PJM Power Pool has been meeting on the subject for one year
District of Columbia	No	Yes. We will be in contact with Maryland, Virginia, and other midAtlantic states
Florida	Staff report discussed issue	Yes, with regards to Gulf Power Company, a member of the Southern Company System
Georgia	No decision at this time	Yes, possibly. With regard to operating companies of the Southern Company

TABLE C-3--Continued

State	Has the Commission Decided How to Treat Costs and Revenues Related to SO_2 Emission Allowances for Setting Rates?	Does the Commission Anticipate Having to Address Multistate Issues? If So, Does It Plan to Coordinate with Other Commissions?
Idaho	No	The only impact in Idaho will be from other states--no plan
Illinois	Staff recommends reconciling costs and benefits through fuel adjustment clause	Yes, Illinois will be required to review Missouri and Iowa jurisdiction utilities' compliance plans No formal coordination plans yet
Indiana	No	Yes, in regards to AEP. The Commission participates in an AEP oversight committee with other states' regulators
Iowa	No	Yes. We hope to coordinate with other commissions
Kansas	No	Yes. Two utilities in Kansas' jurisdiction also serve in Missouri No discussions with Missouri representatives to date
Kentucky	No	Yes. Yes
Louisiana	No response	No response
Maine	No	Examine how NEPOOL functioning will be affected
Maryland	Will be decided by accounting division	Yes. We are and will continue to address multistate issues
Massachusetts	No response	Yes. The New England states may decide to have a meeting to coordinate CAAA compliance

TABLE C-3--Continued

State	Has the Commission Decided How to Treat Costs and Revenues Related to SO_2 Emission Allowances for Setting Rates?	Does the Commission Anticipate Having to Address Multistate Issues? If So, Does It Plan to Coordinate with Other Commissions?
Michigan	Staff consensus is that cost/ benefit approach fits standard ratemaking procedures	Yes. We have participated in the AEP Regional Coordinating Committee with six other states
Minnesota	Not at this time	Although we have some multistate utilities, this is not expected to be a major issue. We plan to communicate plans with other states but probably not develop full coordination plans
Mississippi	Could consider allowances as assets to company and modify performance criteria to measure compliance activities	We will need to address these issues since the Southern Company plans to comply on a "systemwide" basis. No contacts made so far
Missouri	Not at this time	We will face allocation issues with multistate companies. We have not undertaken coordination efforts but intend to, at least informally
Montana	No response	No response
Nebraska	No response	No response
Nevada	No	No
New Hampshire	Cost of compliance will flow through fuel and purchased power adjustment clause	Standing coordination vehicle through New England Governors' Conference's Power Planning Committee. No action to date

TABLE C-3--Continued

State	Has the Commission Decided How to Treat Costs & Revenues Related to SO_2 Emission Allowances for Setting Rates?	Does the Commission Anticipate Having to Address Multistate Issues? If So, Does It Plan to Coordinate with Other Commissions?
New Jersey	Informal consideration has begun, but no decision	Yes. The Commission has initiated an informal dialogue between regional air agencies and PUCs. More formal cooperation is desirable, but difficult to achieve given state-specific concerns
New Mexico	No	Yes
New York	Informal consideration has begun, but no decision	Probably, but too early to specify what actions might be taken
North Carolina	Not yet	No
North Dakota	No response	No response
Ohio	Yes, only preliminary discussions	Yes. Such coordination is taking place through the AEP Regional Coordinating Committee
Oklahoma	No	Yes. Yes
Oregon	No	Yes. We have existing forums for addressing multistate issues and will use those
Pennsylvania	The West Penn Power Compliance filing will be the first case the Commission will rule on	Yes. Coordinating with other state PUCs depends on the complexity of the case or issues. PUCs within PJM region are exchanging information
Rhode Island	Not yet	Yes. The New England Governor's Conference's Power Planning Committee plans to address these issues at its January 1992 meeting

TABLE C-3--Continued

State	Has the Commission Decided How to Treat Costs and Revenues Related to SO_2 Emission Allowances for Setting Rates?	Does the Commission Anticipate Having to Address Multistate Issues? If So, Does It Plan to Coordinate with Other Commissions?
South Carolina	No	Yes. Do not know
South Dakota	No	Yes. No plans at this time
Tennessee	No response	No response
Texas	No decisions made yet	Yes. The Texas Commission will coordinate with other commissions as necessary
Utah	No	Yes. PacifiCorp operates in seven states. We plan to coordinate with other states via the PacifiCorp Interjurisdictional Task Force on Allocations (PITA)
Vermont	No	Some issues may arise in regard to NEPOOL membership. They will be addressed via NECPUC and the Power Planning Committee of the New England Governor's Conference
Virginia	Not yet decided	No
Washington	No	Yes. We plan to coordinate with other commissions
West Virginia	Two decisions	Yes. Informal discussions and development of ad hoc staff committees
Wisconsin	Currently evaluating utility proposals for accounting treatment alternatives	Yes. Not yet
Wyoming	No	Perhaps

TABLE C-4

STATE PUCs: DESIRED INFORMATION AND RESEARCH UNDERTAKEN

State	What Sources of Information from Federal or State Air Pollution Agencies Will Assist Your Decision-Making Regarding Implementation?	Is Your Commission Undertaking Any Major Research Projects Concerning Implementation of, or Compliance with, Title IV?
Alabama	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models	Cost-benefit studies of: - fuel switching
Arizona	Newsletters Training workshops or seminars PC-based compliance planning models	Cost-benefit studies of: - conservation and renewable energy
Arkansas	Electronic bulletin board Newsletters PC-based compliance planning models	No
California	No response	No response
Colorado	Electronic bulletin board Newsletters PC-based compliance planning models	Cost-benefit studies of: - scrubbers - fuel switching - conservation and renewable energy
Connecticut	Electronic bulletin board Newsletters Training workshops or seminars	No
Delaware	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models	No
District of Columbia	Newsletters Training workshops or seminars	No
Florida	Aggregate price information on allowance transactions maintained by some centralized source	Surveys. We conducted a survey of utilities' views on accounting tax issues associated with SO_2 emission allowances

TABLE C-4--Continued

State	What Sources of Information from Federal or State Air Pollution Agencies Will Assist Your Decision-Making Regarding Implementation?	Is Your Commission Undertaking Any Major Research Projects Concerning Implementation of, or Compliance with, Title IV?
Georgia	Newsletters Training workshops or seminars PC-based compliance planning models	No
Idaho	Training workshops or seminars	No response
Illinois	Electronic bulletin board Newsletters PC-based compliance planning models	Cost-benefit studies of: - scrubbers - fuel switching - overcompliance
Indiana	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models	No
Iowa	Electronic bulletin board Training workshops or seminars	No
Kansas	Training workshops or seminars Direct meetings with air quality officials	Cost-benefit studies of: - scrubbers - conservation and renewable energy
Kentucky	Newsletters Training workshops or seminars PC-based compliance planning models	Generic case
Louisiana	No response	No response
Maine	Newsletters Training workshops or seminars PC-based compliance planning models	No response
Maryland	Electronic bulletin board Newsletters Training workshops or seminars	No response
Massachusetts	Newsletters	No

TABLE C-4--Continued

State	What Sources of Information from Federal or State Air Pollution Agencies Will Assist Your Decision-Making Regarding Implementation?	Is Your Commission Undertaking Any Major Research Projects Concerning Implementation of, or Compliance with, Title IV?
Michigan	Newsletters Training workshops or seminars PC-based compliance planning models	Considering opening a docket to hear issues and concerns of interested and involved parties
Minnesota	Electronic bulletin board Newsletters Training workshops or seminars	No
Mississippi	Newsletters Training workshops or seminars	Cost-benefit studies of: - fuel switching - overcompliance
Missouri	Newsletters	Cost-benefit studies of: - scrubbers - fuel switching - overcompliance - clean-coal technology - conservation and renewable energy
Montana	No response	No response
Nebraska	No response	No response
Nevada	No response	Cost-benefit studies of: - conservation and renewable energy
New Hampshire	Newsletters Training workshops or seminars	Commission is not undertaking studies on its own. We are reviewing utility and independent studies
New Jersey	Newsletters Training workshops or seminars Joint USDOE/EPA project on pool-wide integrated resource planning	No response
New Mexico	Newsletters Training workshops or seminars Coordination with State Environmental Improvement Division	Surveys

TABLE C-4--Continued

State	What Sources of Information from Federal or State Air Pollution Agencies Will Assist Your Decision-Making Regarding Implementation?	Is Your Commission Undertaking Any Major Research Projects Concerning Implementation of, or Compliance with, Title IV?
New York	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models	We are not currently undertaking or funding independent analyses A staff Clean Air Act Group has periodic discussions with utilities and New York Power Pool Task Force analyzing various compliance issues
North Carolina	Newsletters Training workshops or seminars	No research
North Dakota	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models Personal contacts and any information such as proposed rulemaking	Nothing yet
Ohio	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models Establishment of Title IV rules and regulations	Cost-benefit studies of: - scrubbers - fuel switching - conservation and renewable energy Economic impact studies Surveys
Oklahoma	Newsletters Training workshops or seminars	No
Oregon	Electronic bulletin board Newsletters Training workshops or seminars	We are looking at fuel switching and alternative resources but not in this context
Pennsylvania	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models	Cost-benefit studies of: - fuel switching Economic impact studies

TABLE C-4--Continued

State	What Sources of Information from Federal or State Air Pollution Agencies Will Assist Your Decision-Making Regarding Implementation?	Is Your Commission Undertaking Any Major Research Projects Concerning Implementation of, or Compliance with, Title IV?
Rhode Island	Uncertain	No
South Carolina	Newsletters Training workshops or seminars	No
South Dakota	Newsletters Consultations	No
Tennessee	No response	No response
Texas	Newsletters Training workshops or seminars PC-based compliance planning models Personal contacts	Surveys Consideration in biannual Peak Demand and Capacity Resources Forecast for Texas
Utah	Newsletters	The Commission is not currently undertaking any major research
Vermont	Newsletters Training workshops or seminars	No
Virginia	No response	Surveys
Washington	Newsletters Training workshops or seminars PC-based compliance planning models	Cost-benefit studies of: - conservation and renewable energy
West Virginia	Electronic bulletin board Newsletters Training workshops or seminars	Cost-benefit studies of: - scrubbers - fuel switching - overcompliance Economic impact studies
Wisconsin	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models	We are reviewing our utilities' research or markets, costs, etc.

TABLE C-4--Continued

State	What Sources of Information from Federal or State Air Pollution Agencies Will Assist Your Decision-Making Regarding Implementation?	Is Your Commission Undertaking Any Major Research Projects Concerning Implementation of, or Compliance with, Title IV?
Wyoming	Electronic bulletin board Newsletters Training workshops or seminars PC-based compliance planning models Anything else available	Not at this time. We are, however, monitoring other studies as we become aware of them

TABLE C-5

UTILITY COMPLIANCE ACTIVITY

State	What Action(s) Have Utilities in Your Jurisdiction Indicated They Intend to Take to Comply with the Title IV Provisions?
Alabama	Identified specific units that are affected Proposed or stated what action will be required to comply
Arizona	Identified specific units that are affected No action has been taken by utilities to date
Arkansas	No action has been taken by utilities to date
California	No response
Colorado	No action has been taken by utilities to date
Connecticut	Identified specific units that are affected Other--presented seminars and briefings
Delaware	Identified specific units that are affected It is IOU's intention to hold allowances for future expansion and compliance needs
District of Columbia	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis
Florida	Proposed or stated what action will be required to comply Have stated how allowances will be used
Georgia	Proposed or stated what action will be required to comply
Idaho	Identified specific units that are affected
Illinois	Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis

TABLE C-5--Continued

State	What Action(s) Have Utilities in Your Jurisdiction Indicated They Intend to Take to Comply with the Title IV Provisions?
Indiana	Proposed or stated what action will be required to comply
Iowa	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis Have stated how allowances will be used
Kansas	See earlier comments on SO_2 emission status of Kansas' coal-fired power plants
Kentucky	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis
Louisiana	No response
Maine	Only one affected unit in phase II in the state
Maryland	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis Have stated how allowances will be used
Massachusetts	Proposed that SO_2 emissions should not be subject to environmental externality add ons
Michigan	Proposed or stated what action will be required to comply
Minnesota	Identified specific units that are affected Discussed a number of possible compliance options
Mississippi	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what actions will be required to comply Have stated how allowances will be used

TABLE C-5--Continued

State	What Action(s) Have Utilities in Your Jurisdiction Indicated They Intend to Take to Comply with the Title IV Provisions?
Missouri	The utilities have submitted reference data (fuel costs, capital costs, O&M costs, emission levels with various fuel and equipment modifications, etc.) that they will use in formulating their preferred compliance strategy
Montana	No response
Nebraska	No response
Nevada	No response
New Hampshire	Identified specific units that are affected Proposed or stated what actions will be required to comply Submitted a compliance plan analysis
New Jersey	Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis
New Mexico	PNM has created a specific group to implement Title IV. At present they are working with the Environmental Improvement Division in developing test and monitoring guidelines. PNM has also looked at the plants which might be affected and done a preliminary analysis of its entitlements and future needs
New York	Identified specific units that are affected Proposed or stated what actions will be required to comply Have stated how allowances will be used
North Carolina	Identified specific units that are affected Commission has not requested any specific action by utilities to date
North Dakota	Identified specific units that are affected

TABLE C-5--Continued

State	What Action(s) Have Utilities in Your Jurisdiction Indicated They Intend to Take to Comply with the Title IV Provisions?
Ohio	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis Have stated how allowances will be used
Oklahoma	No action has been taken by electric utilities to date
Oregon	Identified specific units that are affected Only have phase II units
Pennsylvania	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis Have stated how allowances will be used
Rhode Island	No action has been taken by electric utilities to date
South Carolina	No action has been taken by electric utilities to date
South Dakota	Identified specific units that are affected Proposed or stated what action will be required to comply
Tennessee	No response
Texas	Identified specific units that are affected Proposed or stated what action will be required to comply Some have proposed voluntary pooling of § 406 bonus allowances
Utah	Identified specific units that are affected Proposed or stated what action will be required to comply
Vermont	No action has been taken by electric utilities to date

TABLE C-5--Continued

State	What Action(s) Have Utilities in Your Jurisdiction Indicated They Intend to Take to Comply with the Title IV Provisions?
Virginia	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis
Washington	Identified specific units that are affected No action has been taken by electric utilities to date
West Virginia	Submitted systemwide compliance plan Identified specific units that are affected Proposed or stated what action will be required to comply Submitted a compliance plan analysis
Wisconsin	Submitted systemwide compliance plan Identified specific units that are affected Submitted a compliance plan analysis
Wyoming	Identified specific units that are affected

TABLE C-6

STATE LEGISLATURE: ACTIONS AND STATUTORY CONFLICTS

State	Has Your State Legislature Taken Any Action Concerning Compliance with Title IV?	If Parts of Title IV Are in Conflict with State Statutes, What Has the Legislature Done to Address These Issues?
Alabama	Two bills addressing the Alabama Clean Indoor Air Act passed in the Senate in 1991 but failed to come up for a vote in the House	No statutes have been established
Arizona	No response	No response
Arkansas	No legislative action taken to date	Not applicable
California	No response	No response
Colorado	No legislative action taken to date	None
Connecticut	No legislative action taken to date	No response
Delaware	No legislative action taken to date	None
District of Columbia	No legislative action taken to date	No conflicts identified
Florida	No legislative action taken to date	Not applicable
Georgia	A new statute, HB-280, mandates a new approach to integrated resource planning including precertification of capacity resources. CAAA requirements will impact electric utility filings under this statute	Not aware of any activity
Idaho	No legislative action taken to date	None

TABLE C-6--Continued

State	Has Your State Legislature Taken Any Action Concerning Compliance with Title IV?	If Parts of Title IV Are in Conflict with State Statutes, What Has the Legislature Done to Address These Issues?
Illinois	State acid rain law Legislation concerning preapproval of compliance plans Legislation designed to mandate or predetermine a particular compliance option	None
Indiana	Legislation concerning preapproval of compliance plans	No response
Iowa	No legislative action taken to date	None
Kansas	No legislative action taken to date	Not applicable
Kentucky	No legislative action taken to date	None
Louisiana	No response	No response
Maine	Legislation designed to mandate or predetermine a particular compliance option	None
Maryland	No legislative action taken to date	No response
Massachusetts	Not aware of any legislative action	Not aware of any conflict
Michigan	State acid rain law enacted in 1980 No new legislative action	Not applicable
Minnesota	No legislative action taken to date	No apparent conflicts to date
Mississippi	No legislative action taken to date	No conflicts anticipated
Missouri	No legislative action taken to date	No response
Montana	No response	No response

TABLE C-6--Continued

State	Has Your State Legislature Taken Any Action Concerning Compliance with Title IV?	If Parts of Title IV Are in Conflict with State Statutes, What Has the Legislature Done to Address These Issues?
Nebraska	No response	No response
Nevada	No legislative action taken to date	No conflicts
New Hampshire	State acid rain law predates CAAA	Not applicable
New Jersey	No legislative action taken to date	Existing sulfur-in-fuel limit may limit options available for compliance No action undertaken to date
New Mexico	No legislative action taken to date	State regulations already exceed CAAA levels
New York	No legislative action taken to date	The State Department of Environmental Conservation is reviewing the extent to which Title IV as well as other portions of CAAA are consistent or can be reconciled with New York's State Acid Deposition Control Act No legislative action pending
North Carolina	No legislative action taken to date	No conflicts
North Dakota	No legislative action taken to date	No
Ohio	State acid rain law Legislation concerning preapproval of compliance plans	None required
Oklahoma	No legislative action taken to date	None

TABLE C-6--Continued

State	Has Your State Legislature Taken Any Action Concerning Compliance with Title IV?	If Parts of Title IV Are in Conflict with State Statutes, What Has the Legislature Done to Address These Issues?
Oregon	Enabling legislation for Department of Environmental Quality passed in 1991	Enabling legislation trued up the two
Pennsylvania	No legislative action taken to date	CAAA Conservation Section requires a preapproval DSM program. State PUC regulations do not require preapproval. Our regulations have been made to agree with CAAA
Rhode Island	No legislative action taken to date	No conflicts identified
South Carolina	No legislative action taken to date	None
South Dakota	No legislative action taken to date	Department of Water and Natural Resources is drafting legislation for 1992 session
Tennessee	No response	No response
Texas	State acid rain law No new legislative action taken	Texas Clean Air Act has been modified to conform with the Federal CAAA. The modifications have been comprehensive and not limited only to Title IV
Utah	No legislative action taken to date	No
Vermont	No legislative action taken to date	None

TABLE C-6--Continued

State	Has Your State Legislature Taken Any Action Concerning Compliance with Title IV?	If Parts of Title IV Are in Conflict with State Statutes, What Has the Legislature Done to Address These Issues?
Virginia	No legislative action taken to date	No response
Washington	State acid rain law	Not applicable
West Virginia	No response	No response
Wisconsin	State acid rain law in effect before phase I of CAAA	No response
Wyoming	Previous stringent state statutes concerning emissions and proactive problem solving by utilities, state DEQ, and PSC have resulted in generating facilities in Wyoming which generate allowances. No immediate pressure to modify laws. This is being constantly monitored	None at present

TABLE C-7

STATE AIR AGENCY: REQUIREMENTS ON UTILITIES AND INTERACTION WITH PUCs

State	Has the State Air Agency Or Any Other State Agency Imposed Any Requirements on Utilities Operating in Your State in Connection with CAAA?	Has There Been Or Does Your Agency Plan to Have Any Interaction with Your State Air Agency Regarding CAAA Compliance?
Alabama	None in addition to the Federal guidelines	Not to our knowledge
Arizona	No response	No response
Arkansas	No	No
California	No response	No response
Colorado	No	No
Connecticut	No	Yes. Interagency Working Group established in March 1991
Delaware	Department of Natural Resources and Environmental Control is responsible for administering CAAA compliance	Yes. The Department of Natural Resources and Environmental Control will permit allowance trading
District of Columbia	No	Yes, there will be coordination
Florida	No actions taken or expected	Most interaction has been in the form of information exchange on engineering questions
Georgia	Unaware of any other requirements	Informal liaison at this time
Idaho	No	No plan
Illinois	No	Yes. Ongoing liaison activities

TABLE C-7--Continued

State	Has the State Air Agency Or Any Other State Agency Imposed Any Requirements on Utilities Operating in Your State in Connection with CAAA?	Has There Been Or Does Your Agency Plan to Have Any Interaction with Your State Air Agency Regarding CAAA Compliance?
Indiana	No	Commission will continue to participate in Interagency State Acid Rain Working Group
Iowa	Not to our knowledge	Yes, the agency is participating in the inquiry
Kansas	None yet that we are aware of	Yes. We have agreed that there is a need for face-to-face meetings sometime in the near future
Kentucky	Not to our knowledge	Yes. We have conducted one meeting
Louisiana	No response	No response
Maine	No	Yes, meetings
Maryland	None so far	There is continuing contact with the State Air Agency and Department of Natural Resources
Massachusetts	We are not aware of any such requirements	To the extent that the agency's decisions influence ratemaking and cost allocation issues, we may have to coordinate with that agency
Michigan	No	Yes, we have met with representatives of the Department of Natural Resources, Air Quality Division, and will continue to discuss issues with them

TABLE C-7--Continued

State	Has the State Air Agency Or Any Other State Agency Imposed Any Requirements on Utilities Operating in Your State in Connection with CAAA?	Has There Been Or Does Your Agency Plan to Have Any Interaction with Your State Air Agency Regarding CAAA Compliance?
Minnesota	None to date	At a minimum, there will be informal discussion and interaction, but this has not yet occurred
Mississippi	No	No plans to do so
Missouri	The Department of Natural Resources' Clean Air Advisory Group is currently involved	The Chairman of the PSC is a member of the Department of Natural Resources' Clean Air Advisory Group
Montana	No response	No response
Nebraska	No response	No response
Nevada	No	They sometimes intervene in resource planning dockets
New Hampshire	State Department of Environmental Services is in the process of developing strategy for compliance with CAAA. PUC chairman is a member of the strategy steering committee	Yes
New Jersey	State air agency has stated that, due to local air concerns, allowance purchase may not be an acceptable alternative to scrubbing at a particular affected unit	Yes, in fact the Board of Regulatory Commissioners was recently merged into the DEP to form the Department of Environmental Protection and Energy (DEPE)
New Mexico	They are in the process of development	Minimal to date

TABLE C-7--Continued

State	Has the State Air Agency Or Any Other State Agency Imposed Any Requirements on Utilities Operating in Your State in Connection with CAAA?	Has There Been Or Does Your Agency Plan to Have Any Interaction with Your State Air Agency Regarding CAAA Compliance?
New York	DEC has proposed very stringent draft rules concerning life extension of fossil-fired generating plants that would require the repowering or retirement of such units at forty-five years of service. No date on when or if final action would be taken	There has been routine interaction between DPS staff, DEC, and the NY Power Pool on CAAA
North Carolina	No, except for increasing certain permit fees administered by the Division of Environmental Management (Air Quality Section)	Not yet
North Dakota	Not yet	Not at this time, but there likely will be future interactions
Ohio	Not at this time	Yes, interagency coordination has been established
Oklahoma	Not at this time	No official interaction planned at this time
Oregon	Emission fees have increased pursuant to enabling legislation	We have already coordinated efforts on the Clean State issue
Pennsylvania	Not sure	Yes, we had two meetings with them
Rhode Island	No	Yes. We will meet in December 1991
South Carolina	Not known at this time	Yes. At present only to discuss issues

TABLE C-7--Continued

State	Has the State Air Agency Or Any Other State Agency Imposed Any Requirements on Utilities Operating in Your State in Connection with CAAA?	Has There Been Or Does Your Agency Plan to Have Any Interaction with Your State Air Agency Regarding CAAA Compliance?
South Dakota	Department of Water and Natural Resources is drafting legislation for 1992 session	Very little interaction thus far--expect more in the future
Tennessee	No response	No response
Texas	Texas Air Control Board is considering new rulemaking as a result of Title IV Governor may encourage pooling of bonus allowances allocated under § 406	The Texas PUC and the Texas Air Control Board staffs interact where appropriate
Utah	Not as yet Not immediately	
Vermont	No	No
Virginia	No	Not yet
Washington	Not sure	Yes
West Virginia	No response	No response
Wisconsin	Currently under development	An interagency task force has been working together for some time
Wyoming	Previous stringent state statutes concerning emissions and proactive problem solving by utilities, state DEQ and PSC have resulted in generating facilities in Wyoming which generate allowances. No immediate pressure to modify laws. This is being constantly monitored	Yes

APPENDIX D

UTILITY REGULATION WITH ENVIRONMENTAL CONSTRAINTS

This appendix presents the mathematical model that underlies the findings and recommendations of Chapter 7. The central objective of the model is to bring together two extensive strands of the economics literature: regulatory theory and the theory of marketable pollution permits. The present study is an early attempt at incorporating certain regulatory concerns into a model of marketable emission allowances. Throughout, CAAA provides a unifying theme, for the model and the key mathematical results are designed to shed light upon issues that are new in this legislation.

The material is developed as follows. The following section summarizes the basic model of the behavior of a firm subject to a rate of return (ROR) regulatory constraint (due to Averch and Johnson, 1962), and extends it by the addition of a command-and-control (CAC) environmental constraint. In the last section a market for emission allowances is added. The model developed here is first presented without ROR regulation, and then the full model appears, which considers the behavior of a firm facing environmental regulation (in the form of an allowance market) *and* ROR regulation. Here, firms may choose to buy allowances or to install abatement equipment in order to satisfy the aggregate environmental constraint. Several results are presented that link regulatory provisions in the utility industry with firm behavior in allowance markets. These results underlie the prescriptive conclusions of Chapter 7.

A Model of ROR Regulation with a CAC Environmental Constraint

Suppose that a monopoly firm produces some output q using inputs x (say, fuel) and k_1 (capital). These inputs are available in any quantity at the market prices $w > 0$ and $r > 0$, respectively. For any level of the two inputs, output is determined by the production function $q = f(x,k_1)$. This function takes the usual shape, so that by assumption $\partial f/\partial x > 0$ and $\partial f/\partial k_1 > 0$. The production function f is also assumed to be concave, so that it does not exhibit increasing returns to scale. Thus, monopoly power is derived solely from the firm's market power in the output market. The idea that the firm is a monopolist in its output market is captured by the assumption that its output price p depends upon the amount of q that it offers for sale. Let the demand function be given by $p(q)$, where it is assumed that p is downward sloping in output (the law of demand is satisfied). Once x and k_1 are chosen, q and p are automatically determined.

The firm's emission function is given by $e = h(q,k_2)$, where k_2 is abatement capital. This function is increasing in q and decreasing in k_2. In addition, it is assumed that as output increases, the effectiveness of a unit of abatement capital decreases (that is, $\partial^2 h/\partial q \partial k_2 > 0$). The derivative restrictions guarantee that for any E_0, the function h may be solved for k_2 as a function of q given E_0. Let this function be denoted $k_2 = g(q;E_0)$.

For any given limit E_0 on the firm's sulfur dioxide emissions, compliance may be achieved by reducing output or by increasing the amount of abatement capital or both. Including the cost of scrubbers, the firm's profits are given by $\pi = p(q)q - wx - r(k_1 + k_2)$. The ROR regulatory constraint faced by the firm restricts the rate of return that may be earned on its rate base to an amount $s > r$. In the usual Averch-Johnson (A-J) formulation, this constraint says simply that $\pi \leq (s - r)k_1$. That is, the rate base is considered to be equal to the value of productive capital. Here, some or all of the scrubber may be in the rate base as well. Let $\varphi \epsilon [0,1]$ denote the share of k_2 that is allowed in the rate base. The constraint, then, says the $\pi \leq (s - r)(k_1 + \varphi k_2)$.

Before turning to the decision problem that this firm faces, and the properties of its solution, it will be useful to have in mind the effect that the firm's choice of q has upon consumers' welfare. Using market-level consumer surplus as the measure of the welfare of consumers, it can be shown that consumers are made better off whenever q increases. Given the demand function $p(q)$, let consumer surplus, dependent upon q, be given by

$$CS(q) = \int_0^q p(t)dt - p(q)q.$$

Because much of what follows has to do with how various regulatory decisions affect welfare, it is worth formalizing the following claim at the outset.

Claim B-1. *Suppose that a monopoly producer, facing a differentiable and downward-sloping demand curve, and producing where $q > 0$, chooses to reduce output q. Then consumer surplus is an increasing function of q.*

Proof: Is it sufficient to show that the derivative of CS with respect to q is positive. But this derivative is given by $dCS(q)/dq = p(q) - (p(q) + qp'(q)) = qp'(q) > 0$ for any $q > 0$. But we have assumed that $q > 0$, so that the proof is complete.

Throughout, it shall be assumed that the emissions constraint is binding. In this section, this means that we may write $h(q,k_2) = E_0$. Now, assuming that the ROR constraint is binding, the firm's decision problem may be written

$$\text{(D-1)} \qquad \begin{aligned} \max_{x,k_1,k_2} \pi(x,k_1;w,r,E_0) &= p(q)q - wx - r(k_1 + g(q;E_0)) \\ \text{s.t.} \qquad q &= f(x,k_1) \\ \pi(x,k_1;w,r,E_0) &= (s - r)(k_1 + \varphi g(q;E_0)). \end{aligned}$$

Inserting the equality $q = f(x,k_1)$ into (D-1), the Lagrangian for this problem may be written

$$\text{(D-2)} \qquad \begin{aligned} L(x,k_1;\lambda) = {} & p(q)q - wx - r(k_1 + g(q;E_0)) + \\ & \lambda\big((s - r)(k_1 + g(q;E_0)) - p(q)q + wx + r(k_1 + \varphi g(q;E_0))\big), \end{aligned}$$

where $\lambda \geq 0$ is the multiplier on the ROR constraint.

Given the assumption that the ROR constraint is binding, and assuming an interior solution, the first order necessary conditions for a solution to equation (D-1) may be written

$$\text{(D-3a)} \qquad f_x\left((p + q\frac{dp}{dq})(1 - \lambda) - rg'(q)(1 - \lambda) + \lambda(s - r)\varphi g'(q)\right) - w(1 - \lambda) = 0,$$

$$\text{(D-3b)} \qquad f_{k_1}\left((p + q\frac{dp}{dq})(1 - \lambda) - rg'(q)(1 - \lambda) + \lambda(s - r)\varphi g'(q)\right) - r(1 - \lambda) + \lambda(s - r) = 0$$

$$\text{(D-3c)} \qquad (s - r)(k_1 + \varphi g(q)) - p(q)q + wx + r(k_1 + g(q)) = 0.$$

From (D-3a), which may be written $(MR(q) - rg'(q))(1\text{-}\lambda)+\lambda(s\text{-}r)\varphi g'(q)=w(1\text{-}\lambda)/f_x$ (where $MR(q)=p+qp'(q)$ is the firm's marginal revenue and where f_x denote partial differentiation of f with respect to x), we know that $\lambda < 1$.[1] Combining (D-3a) and (D-3b), we achieve

[1] To see this, note that $\lambda = 1$ is impossible, for otherwise we would have $(s\text{-}r)\varphi g' = 0$, violating the assumption that $s > r$. In assuming that we are at an interior solution, we also guarantee that $\lambda > 0$.

$$\text{(D-4)} \qquad \frac{\partial f/\partial k_1}{\partial f/\partial x} = \frac{r - \lambda s}{(1 - \lambda)w} < \frac{r}{w}.$$

This is the familiar A-J overcapitalization expression, which states that the firm will use more capital than it would if it were minimizing the cost of producing the given level of output.

In the geometrical interpretation of Baumol and Klevorick (1970), this result may be interpreted as follows. Let S denote the set of k_1, x pairs satisfying the ROR constraint. The firm subject to ROR regulation will choose the rightmost point in S, a point that is to the southwest of the efficient or cost-minimizing pair on a given isoquant.

With the environmental constraint, things are a bit more complicated, and the solution depends upon φ. Here, the optimal input choice will be closer to the efficient locus, as the firm substitutes k_2 for k_1 in satisfying its wish to profitably enlarge the rate base.

The profit constraint is given by $\pi = (s - r)(k_1 + \varphi g(q;E_0))$. The firm will choose an input mix so as to equalize the slope of a level curve of this constraint and the set S. The slope of a level curve is

$$\text{(D-5)} \qquad 0 = (s - r)dk_1 + (s - r)\varphi g'(q)(f_x dx + f_{k_1} dk_1),$$

which may be rearranged to yield

(D-6) $$\frac{dx}{dk_1} = -\frac{1 + \varphi g'(q) f_{k_1}}{\varphi g'(q) f_x} = -\frac{f_{k_1}}{f_x} - \frac{1}{\varphi g'(q) f_x} < 0.$$

If $\varphi = 0$, this expression gives the A-J criterion: the firm will maximize k_2. With $\varphi > 0$, the slope of the level curve becomes finite, and the firm optimizes by selecting an input pair that is closer to the efficient locus. Thus, we see that there are efficiency advantages to setting φ at or close to one.

Although the commission can encourage efficiency in production by including scrubbing capital in the rate base, this same treatment also encourages the firm to reduce its output, charging a higher price for its product. Both of these effects harm consumers of electricity. Note first that profits increase for this monopoly firm as its output decreases.

Now, an increase in φ has two effects on q. The direct effect is negative, and is due to the response of the firm to a pure relaxation of the ROR constraint. As allowed profits climb, the firm will scale back production to exploit this opportunity. However, the indirect effect will cause a slight increase in output. This is due to the fact that as output declines so does emissions, and the firm will seek to bring the emissions constraint into play by reducing k_2 and/or increasing q or (and this is most likely) both.

Thus, as the regulator increases φ, two things occur. First, productive efficiency is enhanced. Second, consumer surplus is reduced. This indicates that the decision problem of the regulator is more difficult than one might first think as there is no way to satisfy both of the competing demands of equity and efficiency.

Emission Allowance Trading and Utility Regulation

Let us consider first the case of a monopoly firm that is faced with an environmental constraint in the form of an emission allowance requirement, but is free to earn any level of profit that it can (there is no ROR regulation). In this case, we may write the firm's profit function as $\pi = p(q)q - wx - r(k_1 + g(q)) - p_\ell(\ell - L_0)$, where p_ℓ is the price of emission allowances, ℓ is the number of allowances held by the firm, and L_0 is the number of allowances granted to the firm at the beginning of the period.

Suppose, as before, that the firm uses x and k_1 in the production of electricity q, and that it emits pollution in an amount depending on q and on the level of k_2. Gone is the pollution limit E_0 that appeared in the previous section. It is replaced with an allowance requirement that works as follows. An emission allowance is a license to emit one unit of the pollutant of interest (say, a ton of SO_2). The firm may choose to emit any level of pollution it wishes, so long as it holds allowances in at least that amount. Let ℓ denote allowances or licenses held by the firm, and suppose that it is given an endowment of licenses L_0. These licenses are available to each firm at the price p_ℓ.[2] In this case, we may write the firm's profit function as $\pi = p(q)q\text{-}wx\text{-}r(k_1+k_2)\text{-}p_\ell(\ell - L_0)$, where p_ℓ is the price of emission allowances, ℓ is the number of allowances held by the firm and L_0 is the number of allowances granted to the firm at the beginning of the period.

Inserting the identities $q = f(x,k_1)$ and $\ell = h(q,k_2)$ into this function, the firm's constrained maximization problem is well-defined. The firm chooses x, k_1, and k_2 so as to maximize π. The first order necessary conditions for this problem are

(D-7a)
$$f_x\left(MR(q) - p_\ell \frac{\partial h}{\partial q}\right) - w = 0$$

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[2] For analytical convenience, the allowance market is assumed to be perfectly competitive. Strictly speaking, this means that every emitting firm may obtain all the allowances it wants at the price p_ℓ. This assumption is perhaps the least plausible that has been encountered thus far. Without it, however, one must take account of the strategic, oligopolistic behavior of firms, an issue that shall not be taken up here.

(D-7b)
$$f_{k_1}\left(MR(q) - p_\ell \frac{\partial h}{\partial q}\right) - r = 0$$

(D-7c)
$$-r - p_\ell \frac{\partial h}{\partial k_2} = 0.$$

Combining (D-7b) and (D-7c), we find

(D-8)
$$MR(q) = p_\ell \frac{\partial h}{\partial q}\left(1 + \frac{dq}{dk_2} \frac{1}{\partial q/\partial k_1}\right).$$

From (D-7a), $MR(q) = p_\ell(\partial h/\partial q) + (w/f_x)$, which, together with (D-8), gives

(D-9)
$$p_\ell \frac{\partial h}{\partial q}\left(1 + \frac{dq}{dk_2} \frac{1}{\partial q/\partial k_1}\right) = p_\ell \frac{\partial h}{\partial q} + \frac{w}{f_x}.$$

Totally differentiating the emissions function, we find $(\partial h/\partial q)dq + (\partial h/\partial k_2)dk_2 = 0$, which, together with (D-9) becomes

(D-10)
$$\frac{r}{p_\ell} = -\frac{\partial h}{\partial k_2}.$$

This expression describes the firm's optimal emissions behavior in the absence of ROR regulation. We now examine how the firm's behavior will change when it must satisfy a profit constraint, and in particular at how the solution depends upon the regulatory treatment of allowances.

Suppose that the regulatory authority must choose whether to place emission allowances in the rate base. It is assumed that $\varphi = 1$, an assumption that simply reflects the reality of regulatory practice rather than any normative recommendations that might be drawn from the previous section. Let $\theta \in [0,1]$ denote share of allowances that are considered part of the rate base. If $\theta = 1$ then the firm is allowed to earn the extranormal rate of return s on *all* of its licenses. The ownership of a license to emit one ton of sulfur dioxide into the atmosphere may not appear to resemble ownership of plant and facilities in any material way. Nevertheless, regulatory treatment of ℓ, as we shall see, is critical to the effectiveness of the allowance market.

Once again, the firm's costs include purchases of x, k_1, and k_2 along with the net purchases of ℓ. The firm's new optimization program may be written

$$\max_{x,k_1,k_2} \pi = p(q)q - wx - r(k_1 + k_2) - p_\ell(h(q,k_2) - L_0)$$

$$\text{(D-11)} \qquad \begin{aligned} s.t. \qquad q &\leq f(x,k_1) \\ \pi(x,k_1;r,w) &\leq (s - r)(k_1 + k_2 + \theta\ell(p_\ell/r) \\ h(q,k_2) &\leq \ell . \end{aligned}$$

Program (D-11) may be written in lagrangian form as

$$\text{(D-12)} \qquad \begin{aligned} L = {} & p(q)q - wx - r(k_1 + k_2) - p_\ell(h(q,k_2) - L_0 + \\ & \lambda\big((s - r)(k_1 + k_2 + \theta h(q,k_2)p_\ell/r) - p(q)q + wx + r(k_1 + k_2) + p_\ell(h(q,k_2) - L_0)\big). \end{aligned}$$

The first order necessary conditions for this program may be written

$$\text{(D-13a)} \qquad MR(q) = p_\ell \frac{\partial h}{\partial q}\left(1 - \frac{\theta(s - r)\lambda}{r(1 - \lambda)}\right) + \frac{w}{f_x}$$

$$\text{(D-13b)} \qquad MR(q) = p_\ell \frac{\partial h}{\partial q}\left(1 - \frac{\theta(s - r)\lambda}{r(1 - \lambda)}\right) + \frac{r - \lambda s}{f_{k_1}(1 - \lambda)}$$

Together, (D-13b) and (D-13c) yield

(D-13c)
$$0 = p_\ell \frac{\partial h}{\partial k_2}\left(1 - \frac{\theta(s - r)\lambda}{r(1-\lambda)}\right) + \frac{r - \lambda s}{1 - \lambda} .$$

(D-14)
$$MR(q) = p_\ell\left(\frac{\partial h}{\partial q} - \frac{1}{f_{k_1}}\frac{\partial h}{\partial k_2}\right)\left(1 - \frac{\theta(s - r)\lambda}{r(1 - \lambda)}\right).$$

Using the expression $(\partial h/\partial q)dq + (\partial h/\partial k_2)dk_2 = 0$, and combining (D-13a) and (D-14), we get

(D-15)
$$MR(q) = p_\ell \frac{\partial h}{\partial q}\left(1 - \frac{\theta(s - r)\lambda}{r(1 - \lambda)}\right) + \frac{w}{f_x} .$$

Putting (D-13a) and (D-13b) together, we find

(D-16)
$$\frac{f_{k_1}}{f_x} = \frac{r - \lambda s}{w(1 - \lambda)} .$$

Combining (D-15) and (D-16) and rearranging, we have

$$\text{(D-17)} \qquad -\frac{\partial h}{\partial k_2} = \frac{r}{p_\ell}\left(\frac{r - \lambda s}{(1 - \lambda)r - \theta(s - r)\lambda}\right) < \frac{r}{p_\ell}.$$

The last inequality holds *whenever θ is less than one* because $| r - \lambda s | < | r(1 - \lambda) - \lambda(s - r)\theta |$, where use is made of the fact that the two sides of this inequality agree in sign or else the equality in (D-17) could not hold.

Equation (D-17) is the mathematical result supporting the claim in Chapter 7 that the firm faces a different incentive system under the ROR regime than without it *unless θ is set equal to one.* The results of the previous section, having to do with the efficiency of the productive input mix and the response of output to changes in θ carry over directly to the case with allowance trading.