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PUBLIC UTILITY COMMISSION TREATMENT OF ENVIRONMENTAL EXTERNALITIES

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EXECUTIVE SUMMARY

Many public utility commissions in the United States are considering the environmental consequences or externalities from the generation and distribution of electric power. These environmental externalities are the costs to society that are not reflected either in the cost of the resources that produce electricity or in the price of the electricity paid by consumers. Commissions have adopted various methods to internalize these costs in an attempt to have utility costs reflect the actual cost of electricity production and distribution to society. These considerations are in addition to existing environmental standards prescribed by state and federal legislation.

The consideration of environmental externalities by state commissions has occurred through least-cost or integrated resource planning processes. Externalities are dealt with on a qualitative basis only, explicitly quantified, or on both a qualitative and quantitative basis. The states that quantify externalities use a percentage "adder" to resource costs, apply a scoring system in a competitive bidding process, or monetize specific pollutants.

Traditionally, environmental externalities have been addressed though command-and-control environmental legislation at the state and federal levels and implemented by state and federal environmental regulators. Command-and-control generally refers to environmental standards that are applied at the pollution source and across sources irrespective of emission control costs. Current environmental policy, however, is a combination of command-and-control policies, taxes, and emissions-trading and offset programs both at the state and federal levels.

Emission taxes and trading programs, in general, can achieve a desired emissions level at a lower overall cost than command-and-control programs. The cost-savings potential of these market-based programs comes from the choice sources are given as to how they will comply with the requirements. Sources are allowed to select the method that is the lowest cost for their facilities: (1) control emissions, (2) purchase an emission credit or allowance or pay the emission tax, or (3) some combination of these options. The sources, it is presumed, have better access to information on what are the best options than regulators could readily obtain. An emission-allowance market or a tax can motivate a source to seek the lowest-cost options for compliance by providing an economic incentive to minimize control costs. Overall, this is a more efficient means of internalizing environmental costs than government decree since control occurs at the lower-cost sources; relatively higher-cost sources purchase allowances from the lower-cost sources or pay the tax. Environmental regulators are currently considering or instituting more market-based environmental programs. Examples are the Clean Air Act's allowance trading program and California's South Coast Air Quality Management District emissions offset program.

Environmental programs that affect only new resources--such as adders--are a less effective and more costly means of environmental control than emissions trading or taxes. These methods can have only an incremental impact on existing environmental damage since they only apply to new resources. Emission-control options that affect system operations and existing emissions are more cost-effective; that is, they remove emissions at a lower cost per unit (tons, pounds, and so on) and have a more immediate and a more appreciative positive impact on the environment. The most cost-effective control strategies are a mix of dispatch changes, emission controls, fuel changes and, lastly, resource additions. Environmental programs that can encourage utilities to adopt these control strategies include emission taxes and trading. The cost-effectiveness of these market-based programs--as with any other form of environmental regulation--is highly dependant on the policies of the economic regulatory agencies. For example, the Clean Air Act's allowance trading program has not fully realized its potential cost savings due in large part to the behavior of the state commissions and the Federal Energy Regulatory Commission.

It may be beneficial to ratepayers and society for commissions to first consider assisting in the development of market-based programs and adopt policies that encourage their efficient use. Commissions are generally limited statutorily from directly implementing trading or tax programs. To date, commissions have sought to influence only the choice of supply or demand options for new resource needs. However, under their existing authority state commissions may also attempt to more directly influence existing emissions. This would have the advantage of more directly influencing existing emissions and perhaps achieving emission reductions at costs that approximate market-based programs.

Before deciding to take a more active role in environmental management, commissions should consider at least three factors: (1) their authority within their state to regulate environmental impacts, (2) the role different state agencies play in the determination, development, and implementation of environmental regulations and the commission's most effective role, and (3) the inherently limited scope of the commission's influence on polluting sources with their state.

Commissions have an advantage in terms of being able to analyze emission reduction options and costs and instituting policies that affect utility behavior. As the economic regulator, commissions are in a better position to encourage utilities to implement environmental programs in an effective manner through ratemaking and oversight authority. Environmental regulators clearly have an advantage with respect to calculating social cost and with respect to having authority for implementing more efficient market-based environmental programs. Environmental regulators have better access to environmental damage information, are better acquainted with existing environmental requirements and possible new options, and are in a better position to institute cost-effective programs to address existing emissions.

This asymmetry of authority and information suggests that the best approach may be a cooperative one, where the two agencies exchange information and work together to develop and implement environmental programs. Commissions, in order to have an impact on existing emissions in a cost-effective and timely manner, could cooperate with the environmental agencies in their state to develop and implement existing environmental programs or to develop new ones. This does not suggest or argue for a diminished role for state commissions in environmental management, but an evolving one. This new role would require more cooperation and coordination with environmental regulators, more reliance on performance-based regulation in place of cost-based regulation, and more regional regulatory activity. It also will require commissions to adjust regulatory practices to encourage utilities under their jurisdiction to comply with environmental requirements in a cost-effective manner.

As the electric service industry becomes increasingly more competitive, the future role of state commissions in environmental management will continue to be debated. What type of environmental policy and utility regulation is compatible with a more competitive industry? In the future, the industry is likely to have more independent power production, more wholesale wheeling, and possible retail wheeling. State commissions may have less direct control over approving the development of new resources. This may lead to the development of regional institutions and incentive-based policy tools to address environmental externalities and other market imperfections. Overall, emission limits with trading may be an especially appropriate means of emission control in a competitive environment where multiple sources exist under different jurisdictions.

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FOREWORD

Public utility commissions have taken an increased interest in the environmental impact of electric power production and supply. The issue of whether and to what extent commissions should play an active part in environmental management has been, to say the least, controversial. This report outlines the basic economic rationale for the consideration of environmental externalities, reviews policies to internalize environmental costs, describes the actions of eight commissions on this issue, and analyzes the affect of different environmental regulatory options on utility system operations and costs. Finally the report discusses the role of the state commission in the development and implementation of environmental policy.

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PREFACE

Although this report was a joint and coordinated effort, authors can be identified with specific chapters. Kenneth Rose was project leader and author of Chapters 1, 2, and 7; Paul Centolella was the author of Chapters 3 and 4; and Benjamin Hobbs was the author of Chapters 5, 6, and the appendices.

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CHAPTER ONE

BACKGROUND AND INTRODUCTION

Behind any discussion on whether there are desirable alternatives to utility service disconnection for residential customers who fail to pay their bills is an underlying debate on the proper role of economic regulation of public utilities. The debate includes questions of whether state public utility commissions can or should expand their roles, often without expressed and explicit legislative mandate, beyond that encompassed by traditional ratemaking to accomplish social goals. Some believe that the proper role of a state public service commission does not include the pursuit of social goals, whether those social goals be economic development or preventing social distress to low-income customers. Pricing gas and electricity based on need rather than demand abandons cost-of-service pricing and makes utilities quasi-welfare agencies. Others contend that it is appropriate for state public service commissions to provide or oversee utility provision of certain limited social assistance, such as budget counseling, referral services, and financial assistance, because they are aimed at preventing social distress, such as the disconnection of low-income residential utility service. The outcome of this debate, however, does not require resorting to polar extremes. The fact is that legislatures and commissions believe that the real question is to what extent should the public utility commission provide or encourage the utility to pursue social goals and to what end.

The underlying assumption of this study is that commissions should encourage utility actions that minimize disconnections (thus maximizing service), provided those actions do not unduly adversely affect utility service arrearage and bad debt.

Preference is given to programs that minimize distortion of pricing and billing of services. Preference is also given to programs that minimize the reliance on subsidies and utility class cross-subsidies.

THE OCCASION

This study occurs as traditionally vertically-integrated electric and local gas distribution companies, under the jurisdiction of state public utility commissions, are facing increasing pressures to become more competitive by reducing costs. These competitive pressures come from the more open and competitive wholesale electric and gas markets, where the commodity price of gas now fluctuates at market-driven levels and wholesale power is also becoming more market-driven.

For gas utilities, this increased competitive pressures was facilitated by Federal Energy Regulatory Commission (FERC) Orders 436 and 636, which implement federal policies to provide access to the gas markets at the wellhead. Orders 436 and 636 allow local gas distribution companies and, by state policy in most states, large industrial customers direct access to purchase gas at the wellhead. With the deregulation of gas prices, the existence of a gas supply surplus, and the opening of wellhead access to gas producers, the stage was set for the development of robust gas markets. Allowing large industrial customers to purchase gas at the wellhead helps to expose cross-subsidies that were implicit under traditional cost of service allocations. However, most state commissions take these cross-subsidies into account either by allowing the local distribution company (LDC) (1) to implement "top-down" gas transportation pricing to collect the same fixed costs from a gas transportation customer as it does from gas purchase customers or (2) to enter into a special contract with a customer that may be willing and able to bypass the LDC.

For vertically-integrated electric utilities, the enactment of the Energy Policy Act of 1992 (EPAct) facilitated the development of a more robust and open wholesale power market. EPAct provides for mandatory wheeling of power to wholesale power customers and allows the development of independent power producers (IPPs) that can meet certain requirements to qualify as exempt wholesale generators (EWGs). Thus, increased supply and demand for wholesale power are possible. There are also many utilities with overcapacity, with power to sell on the wholesale power market. These factors set the stage for the development of a robust power market, under circumstances in many ways similar to those that led to the development of a robust gas commodities market.

However, in the case of vertically-integrated electric utilities, there is no requirement of retail wheeling to the ultimate customer. Indeed, EPAct expressly forbids the Federal Energy Regulatory Commission (FERC) from ordering retail wheeling. Instead, a savings provision of EPAct preserves the authority of state commissions to regulate or not to regulate retail franchise areas.

As presented in Figure 1-1 below, traditional cost-of-service allocations usually result in an allocation of the cost of capital burden that favors residential customers over industrial customers. However, as industrial customers are given choices, they will seek to drive down their cost of capital allocation. As discussed below, they will also seek to escape the burdens of any demand-side management or social service programs that favor other customer classes.

Further, as vertically-integrated electric utilities and local gas distribution companies find themselves under competitive pressures to provide services at the lowest possible costs, they will find it tempting to cut social service, conservation, and demand-side management programs. Those programs do not directly contribute to their ability to deliver their product to the customer at the lowest price. (Even if demand-side management programs can be demonstrated to result in a lower total bill for energy services, competitive pressures result in an effort to provide customers with the services that they want at the *lowest possible price*.) Further, there are allegations by customers with choices (typically industrial) that they have to share in the cost of social service, conservation, and demand-side management programs while realizing very little corresponding benefit. Instead, the major benefits of social service, conservation, and demand-side management

Figure 1-1 Here.

FIG. 1-1. THE ONGOING SHIFT IN THE ALLOCATION OF THE CAPITAL RECOVERY BURDEN FROM INDUSTRIAL TO RESIDENTIAL CUSTOMERS (SOURCE: ROBERT E. BURNS, THE NATIONAL REGULATORY RESEARCH INSTITUTE'S NEW

COMMISSIONER TUTORIAL).

programs are alleged to go to residential customers, who are typically thought of as core customers with few choices.

This report is also occasioned by cutbacks in funding of federal social service programs, in particular, the funding of the federal Low-Income Heating Assistance Program (LIHEAP), the principal federal program providing federal funding to provide energy assistance to low-income customers. Indeed, the Clinton Administration proposed to reduce the federal LIHEAP budget from $1.475 billion for Fiscal Year 1994 to $730 million for Fiscal Year 1995. LIHEAP funding provided energy assistance to an estimated 5.2 million households, or 14 million individuals in 1993. The proposed 49 percent cutback of LIHEAP funding would significantly affect the 70 percent of LIHEAP recipients who have an annual income of $8,000 or less, many of whom are elderly or single-parent households. Although opposed in a Resolution of the Executive Committee of the National Association of Regulatory Utility Commissioners at its Winter 1994 Meeting, the proposed cutback on LIHEAP funding was passed by Congress. Further cutbacks in funding of LIHEAP might possibly occur in the future.

Indeed, in late February 1995 the House Appropriations subcommittee cut $1.319 billion for LIHEAP funding for Fiscal Year 1996; and in early March 1995, the full House Appropriations Committee voted to cut the LIHEAP funding for Fiscal Year 1995. The NARUC Executive Committee adopted a resolution at its Winter 1995 meeting, urging Congress to reject any cuts in or recision to LIHEAP funding and to adopt a LIHEAP budget as requested by the Administration for Fiscal Years 1996 and 1997. President Clinton vetoed a recision of current LIHEAP funding. The current House Bill has no specific funding for LIHEAP. Instead, LIHEAP would be rolled-in as a part of a "super grant" to the states. The current Senate Bill will continue LIHEAP as a separately funded block-grant program at $1.3 billion. Many believe that a compromise in the Conference Committee will occur, with the likely result being a cutback in LIHEAP funding.

This report also deals with alternatives to service disconnections for water utilities. Although there is no pressure placed on the water utility industry from emerging competition, nevertheless, the development of state commission policies that require or encourage alternatives to water service disconnection has recently taken on increased importance. In the past, water utility service has been taken for granted as a low-cost utility service, where service disconnection because of an inability to pay was an issue for only very few customers. However, recent increases in the cost of water utility service, caused primarily by infrastructure replacement and secondarily by the cost of complying with the Safe Drinking Water Act as well as the increased demand of water, have made water utility services (drinking water, storm-water management, and waste-water services) less affordable, particularly for low-income residential customers. No longer can the cost of water service be taken for granted. Increasingly, low-income residential customers are finding it difficult to pay their bills and finding alternatives to disconnecting water service has become desirable.

ORGANIZATION OF THE REPORT

This report deals with alternatives to disconnection for electric, gas, and water utility service. Energy utilities are making a transition into a more competitive environment and these competitive pressures have direct implications on the appropriate regulatory approach to help assure that a utility either institutes or maintains an approach that provides alternatives to disconnection of energy utility services. The realities of emerging competitive pressures may force hard choices and innovative approaches to maintain and enhance alternative measures to utility disconnection for electric and gas utilities.

For water utility service, there is little indication of competition or impending competition. Therefore, a more straightforward discussion of alternatives to disconnection is appropriate.

Figure 1-2 shows which state commission staffs responded to the survey. (As in other NRRI surveys three attempts were made to solicit a response from each state.) In subsequent figures and tables, the reader should keep in mind that fig 1-2

the figure only shows those state commissions where a particular type of program is known to exist. It does not necessarily mean that there is not such a program in a state that did not respond to the survey. In subsequent figures, state commissions that have a program are shaded; those that do not have a program are left blank; and state commissions that did not respond are crosshatched. In Table 1-1, the alternatives to disconnection to electric and gas utility service are enumerated and described. Chapters 2, 3 and 4 of this report concerns an evaluation of the impact and effectiveness of programs that are alternatives to utility service disconnection for electric and gas service.

The authors review the electric and gas service disconnection policies of the various states in Chapter 2, including prior notice requirements, winter restriction moratoria, date-based moratoria, temperature-based moratoria, prior commission approval requirements, and service limiters. The pros and cons of each policy are presented. In Chapter 3, the authors conduct a similar review of the billing and pricing arrangement policies of the various states that are presented as part of a strategy to create alternatives to electric and gas utility service disconnection. The pros and cons of each policy are discussed. In Chapter 4, the authors review nonprice, preventive, customer service assistance programs that help to create alternatives to electric and gas utility service disconnection. The discussion also includes pros and cons of each policy. Alternatives for utility disconnection for water service are discussed in Chapter 5. In Chapter 6, the authors provide an empirical analysis of the survey results of alternatives to utility service disconnections for electric and gas service. Finally, in Chapter 7, the authors develop and discuss a positive alternative approach on how state commissions might create incentives for their energy utilities to actively pursue alternatives to utility service disconnection in an increasingly competitive environment and a positive approach toward developing alternatives to disconnection of water service in a monopoly environment.

TABLE 1-1 ALTERNATIVES TO SERVICE DISCONNECTION USED IN THE ENERGY SECTOR	
Measure	Description
Prior notice	Formal notice given by a utility company to residential customers before terminating service due to nonpayment.
Winter restrictions	Procedures other than prior notice that restrict utility disconnection for nonpayment during the winter months.
Date-based winter moratoria	Policies that prohibit winter service termination between during specified dates.
Temperature-based moratoria	Policies that prohibit service termination when the temperature falls below a certain level.
Commission-approved disconnections	Policies that prohibit disconnections subject to approval of the public utilities commission on a case-by-case basis
Payment arrangements	A utility company arrangement in which payment-troubled customers pay arrearage in future installments in order to avoid disconnection or to reconnect utility service.
Temporary service guarantee	A short-term guarantee of service during the winter months if a payment-troubled customers pays a minimum amount of the monthly bill or a certain percentage of annual household income.
Budget billing	Level payments made throughout the year that allow the customer to defer costs of high energy consumption until later months when energy consumption is lower.
Payment extension	Deferral of a utility payment due date to coincide with a fixed-income customer's receipt of Social Security, pension, or other monthly income.
Arrearage forgiveness	Forgiveness of arrearage for select low-income customers who have demonstrated a good-faith effort to pay their utility bills.
Lifeline rate	A baseline rate that is less than the actual cost of service for the utility.
Service limiter	A device that temporarily restricts a household's normal utility consumption.
Below-market conservation loan	A below-market-rate loan from a utility to a low-income residential customer for financing the installation of conservation measures.
Utility-funded weatherization	The use of utility funds to pay for the weatherization of low-income homes.
Energy audits	Free or very low-cost home energy audits to determine existence and location of home energy leaks.
Budget counseling	Counseling by utility personnel to payment-troubled customers to assist in the reduction or elimination of payment problems through the teaching of money management skills.
Referral	Referral of payment-troubled customers to utility and community-sponsored assistance programs.

Source: U.S. Department of Health and Human Services, *LIHEAP [Low-Income Home Energy Assistance Program] Report to Congress for Fiscal Year 1990* (Washington, DC: U.S. Department of Health and Human Services, 1991), 145.

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CHAPTER 2

ECONOMIC RATIONALE FOR TREATMENT OF ENVIRONMENTAL EXTERNALITIES

The recognition of externalities and possible solutions has a long history in economics. The literature on this subject dates back to Alfred Marshall and Arthur Cecil Pigou (together they span from the late 19th century through the 1940s). Pigou in particular did a considerable amount of work in this area in his book first published in 1920, *The Economics of Welfare*.[1] Pigou was among the first to write about the possibility that private and public interests may not always coincide and that government intervention may be necessary. He stated the problem as follows:

> In general industrialists are interested, not in the social, but only in the private, net product of their operations.. . .[S]elf-interest will tend to bring about equality in the values of the marginal private net products of resources invested in different ways. But it will not tend to bring about equality in the values of the marginal social net products except when marginal private net product and marginal social net product are identical. When there is a divergence between these two sorts of marginal net products, self-interest will not, therefore, tend to make the national dividend a maximum; and, consequently, certain specific acts of interference with normal economic processes may be expected, not to diminish, but to increase the dividend.[2]

Pigou identified and defined the problem of what was later designated as externalities. While the strict economic definition has varied over the decades, Pigou's original definition is both useful and generally consistent with recent work in the area:

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[1] A.C. Pigou, *The Economics of Welfare*, 4th ed. (London: MacMillan and Co., Limited, 1932, reprinted 1952).

[2] Ibid., 172.

> Here the essence of the matter is that one person A, in the course of rendering some service, for which payment is made, to a second person B, incidentally also renders services or disservices to other persons (not producers of like services), of such a sort that payment cannot be exacted from the benefited parties or compensation enforced on behalf of the injured parties.[3]

More recent writers prefer a broader definition that would include activities beyond those "for which payment is made." For example, Cornes and Sandler[4] use a broader definition proposed by Meade:[5]

> An external economy (diseconomy) is an event which confers an appreciable benefit (inflicts an appreciable damage) on some person or persons who were not fully consenting parties in reaching the decision or decisions which led directly or indirectly to the event in question.[6]

Meade's definition has two key features: (1) the effect of the externality must be "appreciable" and (2) the effect of the externality falls on a third party or parties who were not a part of the transaction.

An example of an external *benefit* (a positive externality) is a flower garden in front of a house. The owner (or someone else) goes to the trouble and expense to plant

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[3] Ibid., 183.

[4] Richard Cornes and Todd Sandler, *The Theory of Externalities, Public Goods, and Club Goods* (Cambridge, MA: Cambridge University Press, 1986).

[5] J.E. Meade, *The Theory of Economic Externalities in The Control of Environmental Pollution and Similar Social Costs*, as quoted in ibid., 29.

[6] Cornes and Sandler, *The Theory of Externalities, Public Goods, and Club Goods*, 29.

and tend the garden. Passers-by see the flowers, and presumably, get some enjoyment out of what they see (assuming no crowds gather and cause congestion). The home-owner in this simple example is not compensated by the individuals who enjoy the view. An example of an external *cost* (a negative externality) is a factory that emits pollutants into the air as part of the firm's production. The emissions travel down-wind to a nearby community, where it results in higher laundry bills, increased frequency of house paintings, and higher health-care costs, among other costs to the residents. These costs imposed on the community are not considered as part of the economic decisions made by the owners of the factory.

In general, an externality that causes an "appreciable" misallocation of resources is the type that may require government intervention. A subcategory of externalities, however, pecuniary externalities, results from those activities of an individual(s) or a firm(s) affecting another individual(s) but not causing a misallocation of resources.[7] In these cases, government intervention is not necessary. An example is the current changes in the electric services industry. The structural reorganization occurring in the industry is largely the result of the change in the scale economies of electric generation, other technical reasons, and policy changes. The effect of competition from other producers on utility investments is a pecuniary externality. Indeed, this change is likely to result in an *improvement* in resource use (due to an increased incentive to minimize costs). The effect of competition, therefore, on utility investments and the calls for compensation for "stranded investment" cannot be, strictly speaking, based on an externalities argument.[8]

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[7] William J. Baumol and Wallace E. Oates, *The Theory of Environmental Policy*, 2d ed. (Cambridge, MA: Cambridge University Press, 1988), 29-31.

[8] Baumol and Oates (ibid., 30) state "the price effects that constitute the pecuniary externalities are merely the normal competitive mechanism for the reallocation of resources in response to changes in demands or factor supplies."

Of concern here is the category of externalities that do cause a misallocation of resources and are sufficiently large to warrant government action.[9] The presence of an externality, pollution in the production of electricity for example, causes the production and consumption of electricity (and other products and services such as health care) to be different than if the externality did not exist. Figure 2-1 depicts a market condition when the marginal social cost (MSC) is greater than the marginal private costs (MPC).[10] In this case, a negative externality exist, such as with electric generation in the absence of or with insufficient environmental regulation. If it is assumed that MPC equals the price, then the quantity q_p - q_s is the amount of overconsumption of the product. The solution to the problem then may appear to be a matter of raising MPC to equal MSC.[11] However, as will be shown, the matter of how to solve the problem raised by the externality is complicated.

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[9] There is an important vein in the literature that questions the need for government actions with externalities. See Ronald H. Coase, "The Problem of Social Cost," *Journal of Law and Economics* 3 (October 1960): 1-44. This article was largely a response to Pigou. The issues raised in this literature are not explored here since it is assumed, in the case of environmental externalities, the transaction costs are sufficiently high and there are a large number of affected individuals and sources that preclude a noninterventionist solution (for a discussion of this point see Baumol and Oates, *The Theory of Environmental Policy*, 32-35). A broader view, however, would consider the political process as the response. In this case, commissions, legislators, environmentalists, the authors of this report, and others are simply part of the equilibrating process.

[10] The marginal cost curves are depicted upward sloping based on recent work that suggests for the relevant range of output, this is the case. See, for example, Herbert G. Thompson, Jr. and Lynda L. Wolf, "Regional Differences in Nuclear and Fossil-Fuel Generation of Electricity," *Land Economics* 69, no. 3 (August 1993): 234-248. Also note that in the case of pecuniary externalities, there would be no difference between the two curves.

[11] Often in discussions of negative externalities in electricity generation and distribution, the solution is presented as a matter of adding to the MPC. Clearly, as will be explained later, this is *not* what states are doing.

Fig. 2-1. Overconsumption of a good because of a negative externality (Source: Several authors use a similar construct. See, for example, A. Myrick Freeman III, Dallas Burtraw, Winston Harrington, and Alan J. Krupnick, *Accounting for Environmental Costs in Electric Utility Resource Supply Planning*, Discussion Paper QE92-14 (Washington, D.C.: Resources for the Future, April 1992)).

In general, an externality is a category of market failure. That is, they occur, as Pigou surmised, when the operation of private markets by themselves will not equate social costs and private costs and maximize social welfare. The problem often is defined as the absence of a market or lack of well-defined property rights. Optimal or efficient solutions, therefore, often center on the creation of a market by a regulatory authority or legislators.

In his book, Pigou proposed two solutions to the problem of externalities: a tax system such as a effluent fee for negative externalities (often referred to in the literature as a Pigouvian tax) and a bounty or subsidy for positive externalities. Drawing on this early work, others later introduced the idea of marketable permits.[12] While these solutions each have their advantages and disadvantages (discussed below) they are closely related in concept and economic basis. Since environmental externalities are a type of negative externality, this will be the primary focus of the discussion.

The way the market-based alternatives work for negative externalities is shown graphically in Figure 2-2. The horizontal axis in the figure represents tons of the emissions removed (for example, SO_2, NO_x, or VOC) and the vertical axis represents the dollar cost or benefit. The marginal control cost curve is upward sloping because the cost of reducing emissions is progressively more costly as more tons are removed. Put another way, the first few tons of emissions removed have a relatively low cost. For example, a utility can reduce its utilization of its dirtier units and switch to operating its cleaner but more expensive units.[13] However, as these options are exhausted the utility must adopt more costly measures, such as fuel switching, and then more capital-intensive technologies, such as scrubbers. This marginal control cost will vary by utility system. For purposes of illustration, assume the curve in the figure represents the aggregate marginal cost of all sources of emissions in a given area.

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[12] John Harkness Dales, *Pollution, Property, and Prices* (Toronto: University of Toronto Press, 1968) and formalized by W. David Montgomery, "Markets in Licenses and Efficient Pollution Control Programs," *Journal of Economic Theory* 5, no. 3 (1972): 395-418.

[13] For illustrative purposes, emissions by utilities of pollutants such as SO_2, NO_x, and VOCs are considered here. However, the analysis can be applied to other environmental externalities as well, such as the environmental damage caused by the production and distribution of a particular fuel.

The marginal social-benefit curve represents the benefits to society from the emissions reduced. It is downward sloping because of the decline in value of each

Fig. 2-2. Optimal level of emissions under a tax or permit trading system (Source: Baumol and Oates, *The Theory of Environmental Policy*, 59).

subsequent ton removed. The first several thousand tons removed may have a great deal of value to society, for example, by lowering health care costs. The last few tons removed, however, may have only a comparatively small benefit to society.[14]

[14] Of course this depends on the pollutant. Small amounts of lead or mercury may still have a considerable impact on society; they impair children's mental abilities for example. Conversely, the last few tons removed of CO_2 may have a negligible benefit for the global environment (after considerable reductions have occurred).

The intersection of the two curves, the point where marginal social benefit is equal to the marginal control cost, represents the level of emissions that maximizes social welfare. The problem is, How does the environmental regulator achieve this optimum level of emission reduction? Economists have suggested two alternatives. First, the regulator can set an emission tax or emission fee (dollars per ton) equal to t_o in Figure 2-2. Emission sources will then find the point where their marginal control cost is equal to the emission tax and reduce their emissions by that amount, in this case q_o. Up to that point emission sources find it less expensive to reduce their emissions by that amount rather than pay the emission tax (their marginal control cost is less than the tax, up to q_o).

A second alternative to internalize environmental costs is for the regulator to first determine the desired reduction of emissions then set a cap on the total level of emissions. If the total emissions before controls is R and the desired reduction is q_o (as in Figure 2-2, assuming, for the moment, that the regulator knows the optimum quantity to reduce), then the environmental regulator would set the cap, say P, at R - q_o. The environmental regulator would then issue P permits and allow sources to trade the permits. Sources would buy permits from others when the price of the permits is less than their own control cost and would sell permits when the price is above their control cost. This would continue until the price of the permit is equal to t_o, the optimal emission tax and the marginal control cost at q_o. This is basically the type of system, with some modification, created by the U.S. Clean Air Act Amendments of 1990 to reduce and limit SO_2 emissions from electric power plants. In theory, both the tax and permit methods achieve the same level of controls at the same cost.

An important point is that both methods reach the desired level of emission control at minimum cost. The traditional "command-and-control" approach to reducing emissions--requiring each source to reduce emissions by a certain amount irrespective of each source's control cost--is unlikely to lead to the lowest-cost solution.[15] The primary reason for this is

[15] Command-and-control actually takes many different forms. In this report it refers to the issuance of standards by the environmental regulator that are generally applied to all sources of pollution.

because each source has different control costs, has different control options available to them, and has better access to information on their system's operations and control options than the information the environmental regulator can readily obtain.[16] These methods allow more flexibility in selection of control options, allow for changes over time in technology and cost, and provide more incentive to find and use innovative control options. Both emission taxes and permit trading minimize cost, maximize social welfare, and result in the optimum level of emission reduction.

It previously was assumed that the regulator knew the marginal control cost and marginal social-benefit curves in order to set the optimal tax or optimal number of permits. It can be assumed, however, that the environmental regulator always has less-than-perfect information. Figure 2-3 depicts the effect of predicting the wrong marginal control cost curve. Here, it is assumed that the regulator does know the marginal social benefit curve with certainty but believes the marginal control cost is higher, at $MC_{predicted}$, than the actual marginal control cost, MC_{actual}. If an emission tax is chosen, then the regulator will set it at *f* in the belief that the true equilibrium is B. The result is that instead of emissions being reduced by q_p, as expected, they are reduced by q_f (again, because it is less expensive for sources to reduce their emissions than pay the tax up to the quantity q_f). Emissions are reduced too much with a loss in social welfare of AEC.

If a permit trading system was chosen instead, the reduction target would be set at q_p with the result of too little reduction in emissions and a social welfare loss of DAB. Thus, when the predicted marginal control cost is above the actual, the permit system results in too little emission reduction and the emission tax results in too much reduction. The opposite occurs when the predicted marginal control cost is below the actual marginal cost, that is, the tax will result in too little reduction and permit trading

[16] Presumably environmental regulators can also get this information but at a relatively high cost.

Fig. 2-3. Effect of an uncertain marginal-control cost curve on emission levels with an emission tax or permit trading (Source: Baumol and Oates, *The Theory of Environmental Policy*, 62-63).

too much. A similar analysis can be done for the case when the marginal social-benefit curve is different than what was predicted.[17]

[17] Baumol and Oates (*The Theory of Environmental Policy*, 63-73) also note that the magnitude of distortion (welfare loss) will depend on the shape and relative slopes of the marginal cost and benefit curves.

Since the environmental regulator does not know either curve for certain, the actual curve may lie above or below expectations. Given this inherent uncertainty, it is not clear which policy tool is "better." However, the following general points can be made:

- Even with limited information, emission taxes or permit trading systems offer a lower-cost solution to environmental control than command-and-control programs.

- In general, a permit trading system will assure the level of emission reduction, but not the cost of the reduction.

- In general, emission taxes will make the cost of emissions known in advance, but not the level of emissions.

- The focus of the environmental policy is on the environmental benefits, marginal control costs, and how to maximize social welfare.

While market-based programs increasingly are being used by environmental regulators (as reviewed in the next chapter), they face several difficulties when being considered as an option and during their implementation. Barthold[18] notes that market-based programs may be viewed with suspicion by environmentalists since they are "of the market system" that created pollution problems in the first place (that is, pollution results from a "failure" of the market). Command-and-control, on the other hand, are the opposite of market approaches.[19] Trading programs also are cast negatively as trading the "right to pollute."[20] A better understanding of

[18] Thomas A. Barthold, "Issues in the Design of Environmental Excise Taxes," *Journal of Economic Perspectives* 8, no. 1 (Winter 1994): 133-151. See Maureen L. Cropper and Wallace E. Oates, "Environmental Economics: A Survey," *Journal of Economic Literature* 30 (June 1992): 675-740, for a comprehensive discussion of market-based environmental programs.

[19] Adder programs instituted by state commissions (discussed at length in Chapter 4) may have a similar appeal.

[20] News accounts, including those in the *New York Times*, *Wall Street Journal*, and *Associated Press* stories, all used the phrase subsequent to the first SO_2 allowance trades which occurred in 1992.

how markets can be created by governments to alleviate negative externalities can reduce these misperceptions.

Another problem arises in implementing these programs when they are applied to the price-regulated utility industry. In these cases, as with the SO_2 trading market created by the Clean Air Act Amendments of 1990, the regulatory treatment by the commissions determines the level of the savings realized from these programs.[21] Thus far, as documented previously, commissions have yet to adjust their policies to encourage appropriate use of the SO_2 trading market (as buyers or sellers). As a result, the SO_2 market has yet to be broadly utilized by utilities and the anticipated savings has yet to be fully realized.[22]

The methods used to date by state public utility commissions to account for externalities (as briefly described in Chapter 1) are substantially different than those described above. Chapter 4 discusses, in detail, the specific determinations and procedures used by eight states. Chapter 7 discusses the interaction between environmental and economic regulation.

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[21] Kenneth Rose et al., *Public Utility Commission Implementation of The Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, May 1992), Chapters 7 and 9; Douglas R. Bohi and Dallas Burtraw, "Utility Investment Behavior and the Emission Trading Market," *Resources and Energy* 14 (1992): 129-53; and Kenneth Rose, Alan S. Taylor, and Mohammad Harunuzzaman, *Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowances* (Columbus, OH: The National Regulatory Research Institute, December 1993).

[22] Ibid., *Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowances*, Chapter 2.

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CHAPTER 3

POLICY OPTIONS FOR CONTROLLING ENVIRONMENTAL EXTERNALITIES

This chapter provides a broad survey of alternative policies being pursued or available to environmental and utility regulators to address environmental externalities. It examines both the movement toward requiring sources to internalize the cost of externalities through market-based systems of environmental regulation and options available to utility regulators for incorporating externality considerations in utility resource planning or other aspects of utility operations.

Before many state utility commissions, the question of externality valuation has been stalled by controversy or uncertainty regarding how to value specific externalities. If current ambient environmental quality is to be maintained, accommodating economic growth will likely require increasingly stringent and potentially more costly environmental controls. The consideration of externalities, in part, involves not an issue of whether, but of when and how environmental factors will be considered.

Energy and environmental policy typically have been fragmented, with different organizations responsible for utility regulation and environmental protection. Also, no single approach to externality consideration has emerged as dominant. At the state level, environmental protection agencies have set uniform technology-based standards using limited information regarding how to cost-effectively achieve environmental objectives. The attention of state environmental agencies is divided among many categories of sources, types of emissions, and air quality, water quality, and waste disposal issues. In the past, public utility commissions typically have accepted environmental regulations as constraints, not always inquiring as to whether environmental regulations represented the most cost-effective way to achieve environmental quality. While in some states the emergence of facility siting boards in the 1970s began to bring together utility and environmental regulators in the context of permitting for specific facilities, the environmental impact of introducing the facility into the existing utility system was often neglected. Historically, the environmental impacts resulting from the operation of integrated electric utility systems, the cost-effectiveness of controlling specific sources or of measures to reduce those impacts, and the incentives (or disincentives) created by regulation have seldom been examined in a systematic fashion.

This institutional fragmentation provides the context in which environmental externalities are considered. In U.S. environmental regulation, environmental externalities generally arise from one of two situations. First, there are some known or probable environmental costs that are not yet fully regulated, such as greenhouse gas emissions or toxic emissions from utility boilers. Second, under a command-and-control system of regulation, there may be damage costs associated with residual emissions that are greater than the cost of available emission-reduction measures. As noted in the previous chapter, external costs exist when the cost or damages are not included in the source's economic decisionmaking process.

It is important to note that not all residual emissions from utility sources are environmental externalities. From an economic perspective, if sources are required to pay an amount (an actual or opportunity cost) equal to the environmental cost of their actions, the environmental costs are "internalized" and it is possible to achieve an economically efficient result. In an efficient world in which all environmental costs were internalized or borne by the sources of pollution, there most likely would still be residual emissions when the damage caused by the last ton of emissions was less than the cost of an additional ton of emission reduction. Commentators and regulators have not always maintained the distinction between residual emissions and environmental externalities.

Environmental Regulation: Progress Toward Internalizing Environmental Costs

Most U.S. environmental regulation has been in the form of command-and-control requirements. Command-and-control approaches require groups of similar sources to use a specific control technology or comply with a uniform emission rate requirement. For utility air emissions this is typically expressed in pounds of emissions per million Btu of boiler heat input. Command-and-control regulation developed as a result of (1) historical limitations on emissions monitoring technology, (2) fear that more sophisticated approaches could be circumvented, and (3) the apparent administrative efficiency and fairness of uniform standards.[1] In the 1970s, there were significant questions regarding the ability to reliably monitor emissions on a continuous basis, and to track and analyze the large volume of data produced by Continuous Emissions Monitoring Systems (CEMS).[2] Command-and-control regulations could be enforced using periodic spot-checks to determine whether emissions control technology was in place and operating properly. Although monitoring and data management technology have advanced substantially over the last twenty years, substantial portions of the regulatory system continue to follow a command-and-control model.

Command-and-control air pollution control requirements typically must be met either through the use of a specified fuel or by the installation of a specified combustion or postcombustion control technology. Once these measures have been taken, there is little or no value to the source to achieve further emission reductions through improved efficiency or changes in operations. For an electric utility this means that the potential environmental benefits of demand-side management, improvements in generating unit heat rate, power purchases from cleaner sources, or emissions ("full cost") unit commitment and dispatching are not recognized for purposes of environmental compliance. Frequently, additional emission reductions that could be made at a marginal cost that is lower than the cost of some required reductions and potentially lower than incremental environmental damage costs. This is clearly not an economically efficient result.

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[1] For a defense of command-and-control regulation, see Latin, "Ideal Versus Real Regulatory Efficiency: Implementation of Uniform Standards and `Fine-Tuning' Regulatory Reform," *Stanford Law Review* 37 (1985): 1267.

[2] For a history of the development of CEMS technology and requirements, see James A. Jahnke, *Continuous Emission Monitoring* (New York: Van Nostrand Reinhold, 1993), 1-30.

Despite the substantial achievements of U.S. environmental regulation, the command-and-control approach appears to have resulted in paying too much for too little environmental quality. First, such requirements may result in some low-cost emission-reduction measures not being pursued. Second, setting uniform requirements for broad categories of sources often ignores differences in the costs of control at different facilities or the impacts of emissions from different sources. Third, command-and-control regulation has created a perverse set of economic incentives. The approach creates a risk that sources may be mandated to place any newly developed emission control technology on all their facilities. In such an environment, there is little reward for sources to innovate. Indeed, doing so may impose large economic costs. Finally, the development of detailed technology standards is time-consuming, politically controversial, and administratively costly. Environmental regulators simply are not in a position to know what mix of control measures and facility-specific emission rates represent the most cost-effective portfolio of control measures or how that mix should change over time.[3]

Introduction of Emission-Reduction Credit Trading

By 1975, it was apparent that the National Ambient Air Quality Standards (NAAQS) with respect to major pollutants would not be achieved under then current practices in many parts of the country. This led Congress to pass the 1977 Amendments to the Clean Air Act imposing additional technology-based emission limitations on large numbers of emission sources. New and existing sources and sources in different geographic areas were subject to different standards: Lowest Achievable Emission Rate (LAER) for new sources in nonattainment areas, Reasonably Available Control Technology (RACT) for existing sources

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[3] For a more detailed critique of command-and-control regulation, see Bruce A. Ackerman and Richard B. Stewart, "Reforming Environmental Law," *Stanford Law Review* 37 (1985): 1333.

in nonattainment areas, Best Available Control Technology (BACT) for new sources in attainment areas, and New Source Performance Standards (NSPS) for all major new sources. Despite the new technology based standards in the 1977 amendments, many areas continued to experience difficulty moving toward attainment. This created a potential for imposition of potentially devastating federal penalties, including the cutoff of highway funds and bans on the siting of new sources. To introduce some measure of flexibility and allow economic growth in nonattainment areas, the U.S. EPA introduced four types of limited emissions trading: netting, offsets, bubbles, and banking. Despite limited use, these mechanisms reduced air pollution control costs by billions of dollars:[4]

- Netting allows a firm to increase emissions from one unit and avoid regulation as a "major source" by decreasing emissions from another unit within the same facility. By allowing the increase in emissions to be regulated as a "minor," rather than a "major," source, "netting" avoids more detailed permitting, modelling, and monitoring requirements which can cost tens of thousands of dollars and may avoid emission control requirements to which a "major source" would be subject.
- Offsets allow major new sources to locate in nonattainment areas by purchasing emission reductions from existing sources which more than offset the emissions of the new source. EPA adopted an "offset" policy in December 1976 as a means of avoiding mandatory bans on the construction of new and modified sources in nonattainment areas. As a result of the high cost of identifying and securing approval for "offset" transactions, significant "offset" markets have been created in only a few nonattainment areas.
- Bubbles allow a firm to increase emissions at one source in exchange for a larger decrease in emissions at other sources, so long as the total emissions from the

[4] 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* 6 (1989): 109-53.

covered facility(ies) do not exceed the sum of all the sources' individual emission limits. Only a small number of approved "bubbling" transactions have involved trades between different facilities. Frequent changes in EPA's "bubble" policy and the resulting uncertainty have discouraged extensive use of this mechanism.

- Since 1979, EPA had allowed states to establish emission banking programs, enabling firms to save emission-reduction credits. There has been relatively little activity in formal "banking" programs, although more extensive informal "banking" has occurred in some jurisdictions.

Each of these programs resulted in the creation and trading or banking of "Emission-Reduction Credits" (ERCs). The creation and transfer of such credits are subject to prior regulatory approval. To receive certification, an emission reduction was required to be surplus to that required to meet existing requirements, enforceable by state and federal authorities, permanent, and quantifiable in comparison to an established level of baseline emissions.[5] The cost and difficulty of securing regulatory approval have substantially limited the creation and transfer of emission-reduction credits. Trading applications have required costly air modelling, months to be approved, and rigorous regulatory and public review. Litigation regarding EPA's authority to allow trading and a lack of market mechanisms to efficiently identify trading partners also contributed to relatively limited use of these mechanisms.[6] It should be noted, however, that the emergence of emission brokers has created more effective markets for ERCs in some airsheds in the last few years.

Emission Caps in the South Coast Air Quality Management District (SCAQMD)

[5] 51 *Federal Register*, 43829 (December 4, 1986).

[6] For a history and economic analysis of ERC trading programs, see T. H. Tietenberg, *Emissions Trading and Exercise in Reforming Pollution Policy* (Washington, D.C.: Resources for the Future, Inc., 1985).

Prior to passage of the 1990 Clean Air Act Amendments, environmental regulators in Southern California's SCAQMD began developing programs to address the area's extreme ozone problems by providing utility sources with greater compliance flexibility. Relying on state statutory authority, SCAQMD implemented a utility NO_x cap in August 1989. A cap establishes a quantity limitation or average emission rate for a firm or select group of sources, but does not permit trading with sources outside the bubble covering the firm or group.

SCAQMD Rule 1135 establishes system-wide NO_x caps for utility emissions from Southern California Edison, the Los Angeles Department of Water and Power, and the cities of Burbank, Glendale, and Pasadena.[7] The rule contains three NO_x emission limitations. First, it sets declining maximum daily NO_x emission rates expressed in pounds of emissions per net megawatthour (MWh) of generation for the total utility system generation in the SCAQMD area. This limitation is daily because the residence time of NO_x emissions in the air basin is short. Because total or average district-wide rates are utilized, the utility can adjust its generation and power purchases to meet this limit. Moreover, because the emission rate is expressed in pounds per net MWh, improvements in unit heat rate can contribute to meeting the requirement. Second, the rule imposes on Southern California Edison and the Los Angeles Department of Water and Power (effective on December 31, 1999) and on the cities of Burbank, Glendale, and Pasadena (effective December 31, 1989) a maximum daily total number of pounds of NO_x emissions. Third, beginning in 2000, each of these systems also will be limited to a maximum annual tonnage of NO_x emissions. The rule also permits the municipal facilities (Los Angeles Department of Water and Power and the cities of Burbank, Pasadena, and Glendale) the option of linking their power systems to form a municipal bubble with shared daily emission limitations. Southern California Edison is not permitted to participate in the municipal bubble.

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[7] SCAQMD, Rule 1135. *Emissions of Oxides of Nitrogen from Electric Power Generating Systems*, Adopted August 4, 1989, Amended December 21, 1990 and July 19, 1991.

Development of the 1990 Clean Air Act Amendments

During the 1980s, a number of researchers completed studies that found that command-and-control approaches to regulating various pollutants were producing control costs ranging from nearly double to twenty-two times that which would be expected from an efficient market-based system of regulation achieving the same degree of emission reduction.[8] Such findings led policymakers to examine the potential of market-based systems of environmental regulation to reduce compliance costs and provide greater assurance of environmental quality. The 1990 Clean Air Act Amendments include two fundamental market-based reforms: the Title IV Acid Deposition Control SO_2 Allowance Program and the Title I Economic Incentive Program.

1990 Clean Air Act Amendments: Title IV SO_2 Allowances

Electric utilities are planning and implementing strategies to comply with the SO_2 Allowance Program contained in Title IV of the 1990 Clean Air Act Amendments.[9] Under Title IV, 263 units at 110 named generating plants will become subject to SO_2 emission-allowance limitations during phase I, which begins in 1995. Virtually all existing commercial electric generating facilities in the continental U.S. will be subject to phase II, which begins in

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[8] For a review of a series of studies, see Tietenberg, *Emissions Trading and Exercise in Reforming Pollution Policy*. With respect to acid rain control, see also ICF Resources, Inc., *Economic, Environmental, and Coal Market Impacts of SO_2 Emissions Trading Under Alternative Acid Rain Control Proposals*, prepared for The Office of Policy, Planning and Evaluation, U.S. Environmental Protection Agency (Fairfax, VA: ICF Resources, Inc., March 1989).

[9] 42 U.S.C. § 7651 *et seq*. (1990); 40 C.F.R. Parts 72-75. An overview of the allowance system is in Chapter 1 of K. Rose, R. E. Burns, J. S. Coggins, M. Harunuzzaman, and T. W. Viezer, *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992).

year 2000. Title IV is designed to achieve a 10-million-ton reduction in SO_2 emissions from 1980 levels. During phase II, the Act sets a permanent ceiling of 8.95 million allowances on total annual allowance allocations to utilities. An allowance is a limited right to emit a single ton of SO_2 either during the year for which the allowance is issued or, if banked and not used, during any subsequent year. Allowances will be allocated to affected units based upon their historical fuel usage and emission rates. Emissions at affected sources will be tracked through the use of CEMS and the reporting of quality assured data. Emissions in excess of a source's available allowances will result in a reduction in the allowances allocated in the next subsequent year, a $2,000-per-ton penalty, and potential criminal prosecution. Additional sources may "opt-in" to the allowance system.

The allowance system is a fundamental departure from past air quality regulation. Subject to limited exceptions, allowances are a fungible commodity which can be traded between utilities in different states or banked for future use. To date, over $125 million in allowances have been traded.[10] Each allowance has a distinct serial number to facilitate trading and accounting. Allowances may not be used prior to the year for which they are issued, but trading in future year allowances is permitted. U.S. EPA sponsors an annual allowance auction to ensure liquidity in the market and private brokers offer computer bulletin board services to facilitate trading.

The allowance system internalizes the acid deposition costs of SO_2 emissions by attaching potential economic value to each ton of emissions. For every ton of emissions, the utility either must pay to acquire an allowance, or suffer an opportunity cost, in that, in the absence of the emissions, the utility would be in a position to sell allowances.

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[10] M. Murray, "Dealing in Dirt," *California Lawyer* (December 1993): 24. However, it should be noted that the cost and price in most allowance transactions have not been disclosed. Also, not all transactions have been made public. Thus, this number may significantly understate the market activity. A review of the allowance market as of December 1993 is in Chapter 2 of K. Rose, A. S. Taylor, and M. Harunuzzaman, *Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowances* (Columbus, OH: The National Regulatory Research Institute, 1993).

The allowance system constitutes a fundamental change in environmental compliance. First, the allowance system makes it possible to use a range of pollution prevention and control measures that would not be recognized under traditional command-and-control regulations, including emission reductions achieved through changes in unit commitment and dispatch, conservation programs, power purchases, improvements in unit heat rates, and enhancements to transmission and distribution efficiency. Second, it places responsibility for selecting the most cost-effective mix of compliance strategies on utility planners, subject to review by state utility regulators.[11] Third, as allowance trading develops, the market price of allowances should drive utility compliance and operating decisions. For example, algorithms for unit commitment and dispatch that incorporate the value of emission allowances will become the least-cost approach to dispatching generation. Also, utilities are expected to select strategies by comparing the incremental cost of each ton of emission reduction associated with a given strategy to the market price for emission allowances. This should shift compliance activities around the country to the utility systems and facilities where reductions can be most economically achieved. Finally, the opportunity to achieve gains by selling allowances could provide an ongoing economic incentive to develop less costly means of emissions control.[12] The U.S. EPA has estimated that savings from the allowance system could exceed one billion dollars per year.

1990 Clean Air Act Amendments:
Title I Economic Incentive Programs

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[11] The economic regulation of utilities, however, can distort the utility's decisionmaking process away from the most cost-effective compliance strategies. See Rose et al., *Public Utility Commission Implementation*, Chapters 7 and 9; or Ibid., *Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowances.*

[12] See P. Centolella, "Securing the Benefits of Market-Based Environmental Regulation," *The New Clean Air Act: Compliance and Opportunity*, R. Lock and D. Harkawik, eds. (Arlington, VA: Public Utilities Reports, Inc., 1991).

The 1990 Clean Air Act Amendments also authorize the inclusion in Title I State and Federal Implementation Plans (SIPs and FIPs) of Economic Incentive Programs (EIPs), including emission fees, emission-allowance systems, and other economic incentives for achieving emission reductions. Title I includes detailed provisions that rely partly on economic incentives to address one of the most intractable air quality problems: urban smog, the result of tropospheric ozone (O_3) formation. O_3 is formed in a photochemical reaction involving two precursors: NO_x and VOCs. Despite a 10 percent reduction in total VOC emissions and a 30 percent decline in VOC emissions from mobile sources, in the decade following the 1977 Clean Air Act Amendments only limited progress had been made toward the achievement of O_3 standards. For 1988, U.S. EPA estimated that more than 100 cities, containing nearly half of the U.S. population, experienced one or more violations of the O_3 standard.[13] As a result of that experience and a series of modelling studies, the 1990 Amendments placed increased emphasis on strategies that combined NO_x and VOC reductions. Electric utilities account for 32 percent to 35 percent of U.S. NO_x emissions and a small fraction of VOC emissions.[14]

Title I establishes a five-step system of classifying O_3 nonattainment areas; each more severe classification is subject to cumulative or more stringent controls. The Act requires serious or severe areas that are unable to achieve emission-reduction milestones to bump up to higher classifications, adopt contingency measures, or implement EIPs.[15] In extreme nonattainment areas, adoption of incentive programs is mandatory in the event of a failure to achieve any emission-reduction milestone.[16] The philosophy of Title I is that when

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[13] U.S. Environmental Protection Agency, *National Air Quality and Emissions Trends Report, 1988,* Office of Air Quality Planning and Standards, No. EPA-450/4-90-002 (March, 1990).

[14] National Research Council, *Rethinking the Ozone Problem in Urban and Regional Air Pollution* (Washington, D.C.: National Academy Press, 1991).

[15] 42 U.S.C. §7511a(g)(3).

[16] 42 U.S.C. §7511a(g)(5).

prescriptive measures may be inadequate or inefficient air quality agencies should rely on EIPs.

The 1990 Amendments generally authorized the use of EIPs in state implementation plans[17] and specifically for nonattainment areas.[18] The U.S. EPA has issued rules governing EIPs that allow states substantially greater flexibility than the prior EPA emissions trading policies which governed ERC trading programs. The rules require the EIPs to be state and federally enforceable, nondiscriminatory, and consistent with timely attainment of air quality standards and other requirements of the Act. Additionally, programs for nonattainment areas for which credit is taken in an attainment demonstration must have quantifiable impacts, that is, surplus to those of other regulations credited in such demonstrations.[19] Areas with significant O_3 nonattainment problems are beginning to examine the possibility of implementing EIPs with respect to NO_x, and possibly VOC, emissions.

Economic incentive programs for NO_x control have the potential to accelerate the achievement of environmental objectives while substantially reducing the cost of emission control for electric utilities and other sources. First, an effective EIP may make it possible to avoid an expensive second stage of RACT requirements at existing units. The RACT standards, which are projected to be necessary in New England and other serious nonattainment areas, in the absence of an effective EIP, include at least the combination of low NO_x burners and selective noncatalytic reduction technology.[20] New England Electric

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[17] 42 U.S.C. §7410(a)(2)(A).

[18] 42 U.S.C. §7502(c)(6).

[19] Final Rule and Guidance, 59 *Federal Register*, 16690 (April 17, 1994).

[20] Ozone Transport Commission, *OTC Memorandum of Understanding on the Need to Reduce Stationary Source NO_x Emissions and Activities to Develop Technical Support for Regulatory Development* (Washington, D.C.: Ozone Transport Commission, March 10, 1992); Northeast States for Coordinated Air Use Management, *NESCAUM Stationary Source Committee Recommendation on NO_x RACT for Utility Boilers* (Boston, MA: NESCAUM, March 25, 1992).

Power recently agreed to install this combination of technologies at its 750 MW Salem Harbor plant at a capital cost of $25 million, with expected operating costs of $3 to $5 million per year. Considering the total annual reduction in NO_x emissions, the utility expects the combined cost to be about $2,000 per ton of NO_x removed.[21] Second, an EIP could take a seasonal approach, recognizing that NO_x contributes to O_3 formation only during warm, sunny summer months, and at specific relative concentrations of NO_x and VOC emissions. Of the fifty-five areas which exceeded the O_3 standard during the period of 1989 through 1991, only six did so on more than ten days per year.[22] Third, incentive programs might take advantage of geographic differences in the contribution of NO_x emissions to ozone formation. Utilities could be encouraged to simply shift generation away from urban areas during periods of high O_3 formation.

Illinois Title I NO_x EIP Proposal

In September 1993, the Illinois Environmental Protection Agency released for public comment a draft proposal for a NO_x emissions trading system for northeastern Illinois.[23] The proposal was the product of a collaborative design team that included representatives of the Illinois EPA, Commonwealth Edison, and the Environmental Defense Fund. All or portions of eight counties in northeastern Illinois, which are classified as severe ozone nonattainment areas, would be included in the program.

[21] "New England Power to Cut Salem Unit NO_x Using Experimental Process," *Utility Environment Report* (November 27, 1992), 15-16.

[22] U.S. Environmental Protection Agency, "EPA Data Show Steady Progress in Cleaning Nation's Air," *EPA Environmental News* (October 19, 1992).

[23] "Draft Proposal: Design for NO_x Trading System," Unpublished paper, Illinois EPA, September 22, 1993, Chicago, Illinois.

The Illinois draft proposal would create a seasonal NO_x marketable permit program from May 1 through September 15, based on the occurrence of ozone exceedances in Chicago and downwind nonattainment areas. The proposal recommends that emission units that emit at five or more tons per season, located at stationary sources emitting twenty-five tons or more per season, be required to participate in the program. Such sources account for over 86 percent of stationary source NO_x emissions during the four and one-half month ozone season.[24] Smaller sources would be allowed to opt into the program. Additionally, mechanisms would be considered to give credit for old car scrappage programs or the accelerated use of clean fuels in vehicle fleets. Seventy-one percent of NO_x emissions in the region are from mobile sources, while only 27 percent originate at stationary point sources.[25]

The proposal would establish the Northeast Illinois Clean Air Market (NICAM). Affected sources would be able to exchange NO_x Trading Units (NTU), with each NTU equal to 200 pounds of NO_x emissions. An NTU could be banked from year to year for up to three ozone seasons. The Illinois EPA would establish a market exchange system in which participating sources, brokers, and other parties could open accounts and engage in trading activity. Although an NTU could not be used prior to the season for which it was issued, trading in future-year NTUs would be permitted. The Illinois EPA also would establish a regular account monitoring and review system to protect against improper activities. To ensure market liquidity, a portion of the NTUs would be set aside and sold at auction each year.

Beginning in 1997, each affected source would be allocated NTUs and be expected to have sufficient NTUs to cover its seasonal NO_x emissions. Allocations would be based on a fixed percentage of emissions during a baseline period, such as 1992 through 1995. The allocation of NTUs would decline from year to year based on the total NO_x reduction that is necessary to achieve emission-reduction milestones and attainment by the year 2007. This

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[24] Ibid.

[25] Ibid.

deadline is set by the 1990 Clean Air Act Amendments, and the required reduction will be based on air quality modelling for the Illinois EPA's attainment demonstration.

Many of the sources covered by the proposal could be required to install CEMS under a pending U.S. EPA rulemaking on enhanced monitoring. Until the federal rule is final, the proposal does not address how monitoring will be addressed at smaller sources that may not be required to install CEMS.

A second unresolved issue is the disposition of NTUs from inactive or shutdown sources. One option under consideration is that such NTUs could be retained by the state and used in a community bank to facilitate economic development.

The Illinois proposal could have a significant effect on reducing utility NO_x control costs. Eight of the sixty-three sources which would be required to participate are utility power plants. These eight sources together account for 57 percent of the seasonal emissions from all sources covered by the program.

SCAQMD's RECLAIM Program

In October of 1993, SCAQMD also adopted its Regional Clean Air Incentives Market (RECLAIM) program.[26] RECLAIM is an emissions trading program for NO_x and SO_2 emissions covering most major stationary sources in the South Coast Air Basin. Electric generation is included in the RECLAIM NO_x program, but due to Title IV it is not included in the RECLAIM SO_2 trading program. Under each program, affected sources receive annual allocations of RECLAIM trading credits (RTCs). The credits are denominated in pounds of emissions in a given year and expire at the conclusion of that year. Credits may be transferred from source to source, provided that the transfer applies to the current compliance year the seller indicates that the RTC has become available. The RTC must become available as a result of (1) process change,
(2) addition of control equipment, (3) production decrease, (4) equipment or facility

[26] SCAQMD, Regulation XX, Rule 2000, *et seq*.

shutdown, or (5) if the seller is not a RECLAIM facility, the cause has been previously reported. To ensure enforcement, the rule provides for continuous emissions monitoring and administrative penalties. The district maintains a listing of the ownership of trading credits. Sources must report emissions and a reconciliation with trading credit holdings on a quarterly and annual basis. The rule also provides that emission-reduction credits and external offsets may be recognized in the allocation of RTCs. Also, the rule allows for the generation of trading credits through mobile source programs to scrap older high-emitting automobiles.

Northeast States for Coordinated Air Use Management NO_x Proposal

A proposal for a regional NO_x cap or system of NO_x caps, structured as a marketable permit system, is under consideration by the Northeast States for Coordinated Air Use Management (NESCAUM). NESCAUM is the regional air policy support and coordination agency for air regulators in the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Since April 1992, NESCAUM has been exploring the feasibility of a multistate, market-based emissions trading program which could include elements from the federal Title IV SO_2 emission-allowance system, the South Coast Air Basin's utility-wide NO_x cap system, and SCAQMD's RECLAIM program. NESCAUM is investigating a market-based NO_x regulation because it offers increased certainty of achieving emission reductions, greater flexibility for sources in meeting reduction targets to choose the lowest-cost option available, and the potential for incidental reductions in emissions of SO_2, particulates, air toxics, and CO_2 by encouraging energy conservation and fuel switching. NESCAUM is currently undertaking a study to address technical and policy issues including the determination of baseline emissions, the number and types of sources to be included, the geographic scope of the system, and the administrative procedures necessary to administer a multistate trading system and integrate such a system into permits and state implementation plans.[27] The specific structure of the NESCAUM plan has not yet been determined.

Other Potential Applications of NO_x EIPs

NO_x EIPs similar to those being implemented in the South Coast Air Quality Management district and under consideration in Illinois and the Northeast could largely internalize the environmental costs of NO_x emissions associated with ozone nonattainment. Other serious and severe O_3 nonattainment areas that could consider this approach include: other portions of central and southern California; southeastern Texas; the New Orleans metropolitan area; southeastern Wisconsin and western Michigan; the Atlanta metropolitan area; and the remainder of the Northeast Ozone transport region, which includes the states of Delaware, Maryland, and Pennsylvania and the District of Columbia metropolitan area. NO_x EIP is particularly attractive because it offers a potentially less costly strategy than the alternative of a second phase of RACT standards on all existing sources, which otherwise could be required under the 1990 Clean Air Act Amendments.

Market-Based Regulation and Greenhouse Gases

Because greenhouse gases are a uniformly mixed global pollutant, there has been substantial interest in using market-based approaches in structuring any greenhouse gas reduction program. The international Framework Convention on Climate Change[28] authorizes joint implementation that could develop into a system of emissions trading at an international

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[27] NESCAUM, *Development of a Market-Based Emissions Cap System for NO_x in the NESCAUM Region: Project Summary for Section 105 State Air Grant Funds for Market-Based Initiatives* (Boston, MA: NESCAUM, September 1992).

[28] This is an agreement signed by 161 countries at the Earth Summit held in 1992 in Rio de Janeiro, Brazil.

level. In its initial 1993 budget proposals, the Clinton Administration proposed the use of energy taxes to partially internalize the risks associated with growing atmospheric concentrations of greenhouse gases. Although these proposals were not accepted in the 1993 budget package, the Administration has articulated an objective of stabilizing greenhouse gas emissions at 1990 levels by the end of the decade and is negotiating a series of voluntary reduction agreements with utilities under its Climate Challenge program.[29] In part, to provide a basis for recognizing current greenhouse gas reductions in any future mandatory control program, Section 1605 of the 1992 Energy Policy Act creates a database to track and allow for voluntary reporting of activities leading to reductions in greenhouse gas emissions. The U.S. Department of Energy is currently developing protocols for such reporting. Other functions of Section 1605 include providing public recognition for reduction activities, social learning regarding activities being pursued, and evaluation of progress toward greenhouse gas stabilization.

Regulation: Options for Improving Consideration of Environmental Externalities and Internalizing Environmental Costs

In Chapter 1, this report described how utility regulators to date have relied on qualitative consideration or adders to take externalities into consideration in reviewing utility resource plans and have seldom considered externalities outside of the resource planning and procurement process. In the next chapter, detailed case studies regarding how externality considerations have been implemented in eight states are provided. In other portions of the report, limitations of the adder approach and of limiting consideration of externalities to resource planning are discussed. In this section, policy options that may be available to utility regulators, other than adders or qualitative consideration in resource planning, that could

[29] For a comprehensive overview of programs to encourage voluntary greenhouse gas reductions, see *Climate Change Action Plan* (Washington, D.C.: Office of the President, 1993).

improve commission practices are discussed. For example, by utilizing the environmental performance standard option discussed below, utility regulators could achieve many of the economic efficiencies inherent in the market-based systems of environmental regulation discussed in the preceding section.

Some commissions have adopted relatively high adder values based on the cost of complying with command-and-control requirements, but have applied those values only to the planning and acquisition of new resources. Applied in this context, adders have limited impact on near-term costs and emissions. Moreover, when major new resources are needed, such adder values may not accurately reflect the damage which would be caused by residual emissions. It should be remembered that command-and-control environmental standards, such as LAER (applied to new units in nonattainment areas), are designed not only to achieve emission objectives, but also to allocate costs between new and existing units. Indeed, new units in nonattainment areas may be required to meet both LAER emission rates and purchase offsets for their residual emissions at a greater than one-to-one ratio. In this case, a more stringent LAER standard implies that fewer offsetting emission reductions would be purchased and area emissions could be higher than would occur under a less stringent LAER standard.

While a great deal of attention has been given to the development of adder values in resource planning, it is often overlooked that there are relatively inexpensive pollution prevention and emission-reduction measures which are not addressed either by adders as currently applied or by command-and-control environmental regulation. Because command-and-control, which continues to be the dominant form of environmental regulation for most pollutants, requires only that a particular technology or emission rate (for example, pounds per mmBtu) standard be met, measures such as changes in unit commitment and dispatch, heat rate improvements, or demand-side management (both conservation and replacement of fossil fuel end uses with more efficient electrotechnologies) are neither recognized nor encouraged by most environmental regulations. In many cases, such measures could provide a significant, immediate environmental improvement at an incremental cost below even conservative estimates of the environmental damages associated with residual utility emissions.

One of the best options available to utility regulators is to work with environmental regulators to support the development of market-based systems of environmental regulation. However, it is not always possible to rely solely on environmental regulators adopting market-based systems which will efficiently internalize environmental costs. Environmental regulators work within a comparatively inflexible framework for developing and implementing state implementation plans for meeting emission-reduction milestones and ambient air quality standards. Environmental regulators, burdened with implementing statutory command-and-control requirements for thousand of sources, may find it difficult to develop a new framework for regulation. In an ideal situation, utility and environmental regulators would closely coordinate their polices selecting the mix of policy options which most effectively balances reducing environmental risks and limiting emission-reduction costs. However, given environmental regulation by command-and-control standards, utility commissions may wish to encourage adoption of inexpensive measures with incremental costs less than the damage costs associated with residual emissions.

This section identifies policies which could be used to encourage the adoption of such measures or to build consensus regarding preferred economic and environmental strategies. It can be difficult and costly to develop comprehensive and reliable damage-cost assessments. However, even a less than comprehensive assessments may identify minimum values with an acceptable degree of reliability. This section also identifies on-going efforts to improve and implement damage costing methodologies.

Again, it is important that regulators place the issue of externalities into perspective. Not all residual emissions are externalities and not all externalities have a value sufficient to significantly change utility resource planning or operational practices. To date, it has primarily been externality valuations associated with SO_2, NO_x, and CO_2 that have appeared to be significant for utility resource planing purposes. Market-based systems of regulation already are beginning to internalize the acid deposition impacts of utility SO_2 emissions and are being developed in several states and regions for NO_x emissions. Utility greenhouse gas emissions (and in some parts of the country NO_x emissions) continue to present significant externality issues. Following the completion in 1993 and 1994 of U.S. EPA studies related to utility emissions of air toxics and mercury,[30] air toxics also may become a significant issue. Other issues, such as electromagnetic fields, water use, impacts on endangered species, or effects on scenic, historic, or cultural sites may continue to be significant, primarily at a regional, site, or project-specific level. By focusing on the significant utility system impacts of key environmental pollutants (or fuel cycle impacts where data are available), utility regulators can have a meaningful impact on improving environmental quality and reducing possible future control costs.

The options examined in this section include:

- Improved Damage Cost Assessments. Damage cost assessment may provide a reasonable floor for estimating externality costs. The results of damage cost assessments may be used in setting adders, case-by-case trade-off analysis, or in internalizing environmental costs through performance standards.

- Multi-Attribute Trade-Off Analysis. In the absence of consensus regarding environmental valuation, it can be useful to examine the frontier of tradeoffs among a variety of policy options. This may occur either in the context of selecting among specific resource alternatives or in designing a performance standard to more fully internalize externality costs.

- Environmental Performance Standards. By extending incentive regulation to environmental practices, utility regulators lead utilities to act as if environmental costs were internalized. Such an approach may be applied either to specific

[30] 42 U.S.C. § 7412 (m) and (n).

environmental issues, such as enforcement of utility Climate Challenge commitments or to a broader index of utility environmental performance.

- Green Pricing. Green pricing tariffs provide environmentally-conscious consumers the option to pay a premium rate in return for additional investments in renewable or other environmentally benign resources.

Improved Damage Cost Assessment

Comprehensive damage cost valuation represents a preferred approach to valuing environmental externalities. However, developing complete damage cost assessments is a difficult process. The path of damages must be traced through consecutive steps:

- A geographic and time-specific inventory of emissions;
- a representation of the dispersion of emissions in space and time;
- determination of chemical reactions generated by emissions in the environment;
- identification of the populations of humans, plants, animals, and materials affected by the emissions and their chemical products;
- for each of these populations, determination of a dose-response relationship; and
- for each response, a valuation of significant impacts.

There are a number of efforts under way to make or improve damage cost assessments. In addition to the New York study described in the next chapter, three other efforts deserve specific mention.

- The California Energy Commission developed an Air Quality Valuation Model. The model uses a damage function approach to translate emissions from electric supply options at various locations into specific air quality impacts. Results from initial analyses were included in the Energy Commission's 1992 Electricity Report. Additional work is now under way to include acid deposition, ecosystem effects, mobile source emissions, environmental impacts on water quality and biological resources, and hazardous wastes.

- In preparation of a Draft Environmental Impact Statement (DEIS) for its resource programs, Bonneville Power Administration conducted a series of studies to estimate damage costs associated with specific resource options.[31] Separate studies of air quality and visibility effects, human health effects, and ecological effects were conducted to produce the original physical effects data needed to evaluate the impacts of different power generation scenarios. The physical effects data were then incorporated into an economic analysis, combining price data for market goods, such as crops, with values produced by contingent and hedonic valuation studies for nonmarket goods, to calculate the total cost associated with the environmental effects of each of the alternatives. Contingent valuation analysis estimates the economic value of health and environmental risks based on survey respondents' reported willingness to pay to avoid those risks. Hedonic valuation measures the values implicit in differences in the observed market value of otherwise similar employment opportunities, goods, and services. The basic techniques used in the DEIS to value environmental impacts were market prices for traded goods, contingent valuation, hedonic wage, hedonic property value, and travel cost methods. Among the specific environmental impacts valued were human health effects, visibility, crop reductions, wildlife impacts, impacts on forest recreation areas, and impacts on recreational fishing.

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[31] Bonneville Power Administration, U.S. Department of Energy, *Draft Environmental Impact Statement Resource Programs*, DOE/ERS-0162 (Portland, OR: Bonneville Power Administration, March 1992).

- Examining a potentially broader range of impacts, the U.S. Department of Energy and the Commission of the European Communities are evaluating the external costs and benefits associated with the major fuel cycles involved in energy production. The purposes of the study are to (1) create a unified conceptual design for quantifying the various costs and benefits associated with the production and consumption of energy from different fuel sources,
(2) demonstrate an accounting framework that can be used to estimate the static measures of a broad range of costs that result from the incremental use of different fuel types and use this information in comparative analysis, and
(3) identify critical methodological issues and information needs that will affect expanded efforts to develop comprehensive assessments of the costs of energy use. The objective is to develop a damage function approach which will estimate the damage or aggregate willingness to pay for avoiding a given set of environmental impacts associated with the development of a new electric generation facility. This study is unique because it considers the entire fuel cycle from resource extraction, through energy conversion, to waste disposal. Background information regarding the approach and issues which would be addressed in the studies is currently available, although the specific methodologies and valuations remain under development.[32]

As these and similar efforts, including those under way in New York and Wisconsin, are completed, substantially improved data and accounting methodologies should become available for making damage cost assessments.

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[32] Oak Ridge National Laboratory and Resources for the Future, *U.S./EC Fuel Cycle Study: Background Document to the Approach and Issues, Report No. 1 on the External Costs and Benefits of Fuel Cycles: A Study by the U.S. Department of Energy and the Commission of the European Communities*, ARNL/M-2500, DE93 004291 (Oak Ridge, TN: Oak Ridge National Laboratory and Resources for the Future, November 1992).

Building Consensus: Multi-Attribute Trade-Off Analysis

In the absence of reasonable consensus regarding externality valuations, how can regulators, utilities, and other affected parties identify and seek consensus regarding the acquisition of specific resources or an environmentally conscious resource strategy? One approach is to: (1) analyze a number of resource alternatives under a range of possible future scenarios; (2) identify those options that offer the lowest cost for different levels of emissions (so as to define an efficient trade-off frontier between direct costs and environmental quality); and (3) identify preferred strategies that robustly appear on the efficient trade-off frontier under a variety of conditions. This approach to negotiation and decisionmaking under uncertainty is called scenario-based multi-attribute trade-off analysis.[33] Multi-attribute analysis focuses attention on tradeoffs among economic, environmental, and/or other attributes by analyzing the performance of multiple strategies under a range of future scenarios (for example, high and low oil prices, load growth, or partial environmental valuations) and applying carefully constructed rules to identify strategies and develop optimal trade-off frontiers (this is discussed in Chapters 5 and 6). The analysis may identify sharp breaks in the trade-off frontiers where substantial improvements in environmental quality can be captured at a minimal incremental economic cost. With faster computers, it is possible to

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[33] Clinton J. Andrews, "Spurring Inventiveness by Analyzing Trade-Offs: A Public Look at New England's Electricity Alternatives," *Environmental Impact Assessment Review* 12 (1992), 185; Stephen R. Connors, "Side-Stepping the Adder: Planning for Least-Social-Cost Electric Service, *Proceedings of the National Association of Regulatory Utility Commissioners-U.S. Department of Energy Fourth National Integrated Resource Planning Conference* (Washington, D.C.: NARUC, September 1992); Connors, "Externalities, Adders and Cost-Effective Emission Reductions: Using Trade-Off Analysis to Promote Environmental Risk Mitigation," *Proceedings of the American Power Conference, Volume 1* (April 1993), 697.

look at a large number of strategies and scenarios. If undertaken in an interactive fashion, it can help planners (and other parties) to identify new strategies.[34]

The approach has limits. First, the number of attributes included in the analysis should be limited in order to make the analysis tractable and so that accepted dominance rules can be helpful in identifying preferable strategies. If there are one or two environmental effects, or weighted aggregations of effects, about which there is significant uncertainty or disagreement, this approach can play a valuable role in identifying preferred options. This means that analysts may have to develop a composite indicator of environmental quality, assign monetary valuations to some externalities, or address issues in stages to ensure that the analysis remains manageable. Second, if this approach is used as a fact-finding component in a multi-party negotiation or consultation, the parties must be willing to agree on the assumptions for the analysis and to defer normative discussions until the results of the analysis are available to provide a factual context. The value of multi-attribute analysis in a negotiation is that it allows parties to identify the costs and benefits of real options. It opens the possibility that one or more options may be mutually acceptable even though the parties are applying different normative standards to their own evaluations of the alternatives. Third, the data and modelling requirements of this approach can be substantial; effective participation in and review of multi-attribute analysis requires a substantial commitment by regulators and affected parties.

Performance Standards: Shared Environmental Savings

Regulators increasingly consider incentive regulation to introduce the incentives and discipline that would be present in competitive markets. In a similar manner, environmental incentives programs can mimic the incentives and achieve many of the benefits of market-

[34] For a description of the adoption of the trade-off approach, please refer to the Connecticut case study in Chapter 4.

based environmental regulation. Under the adder approach, additional emissions have no negative financial implications for the utility. Adders act as a shadow price only in decisions where their use is mandated by regulators. Thus, adders do not create the economic incentive to identify and implement lower-cost means of reducing emissions.

Many commissions have adopted performance standards and incentives with respect to power plant availability, heat rates, fuel purchasing, or other aspects of utility operations. Incentive-based environmental performance standards could be adopted to help enforce utility commitments under the Department of Energy's Climate Challenge program or to encourage adoption of a broader range of environmental improvements. Such standards could provide incentives to identify and implement low-cost emission-reduction measures not recognized in command-and-control environmental regulation. The Climate Challenge program is a voluntary program under which agreements will be negotiated with utilities to limit or reduce greenhouse gas emissions. More than sixty utilities have indicated to the Department of Energy their willingness to enter into negotiations to establish such agreements. Resulting emission reductions would be reported to the Department under the 1992 Energy Policy Act § 1605(b) voluntary reporting structure. Alternatively, performance standards and incentives could be structured to secure improvement in a broader index of utility emissions.

There have been reported efforts to negotiate environmental performance incentives, although, to date, none of these negotiations has proven successful.[35] Four key elements are needed to establish an incentive-based performance standard:

- A baseline level of emissions from which to measure environmental performance.
- A reasonable and achievable target for environmental improvement such that incentives (and disincentives) may be tied to the percentage of target improvement achieved.

[35] Jonathan B. Lowell, "Integrating Planning and the Environment at New England Electric," *Proceedings of the ACEEE 1992 Summer Study on Energy Efficiency in Buildings* (Washington, D.C.: ACEEE, August 1992), 9.125.

- A maximum incremental cost per ton of reduction up to which the utility may reasonably spend, such that the utility is not induced to make imprudent expenditures to achieve minor incremental improvements in performance.
- A structure of incentives (and disincentives) sufficient to motivate performance.

Baseline emissions could represent simply average historical emissions for a representative period of years. This is the approach which was utilized in Title IV of the 1990 Clean Air Act Amendments. This simple approach, however, does not take into consideration the range of external factors (for example, economic growth, fuel costs, weather, prices of competing energy resources, and so on), which may influence a utility's environmental performance. An alternative that would take such factors into account would be the development of a dynamic statistical measure. Similar to how utilities develop statistical models for making short term load forecasts, for many utilities it may be possible to develop a reasonable statistical model that estimates emissions based on coefficients developed from historical data. Such a model could take into consideration changes in population, local economic activity, relative prices of electricity and other energy sources, fuel prices, weather, and other variables. The statistical model would be developed and tested in advance based on the historical relationship of such variables to system-wide emissions. When actual data for population, economic activity, etc. became available in future years, it would be introduced into the model, and together with historically derived coefficients, used to backcast expected emissions under actual economic, weather, and other conditions. Actual utility emissions could then be compared to these expected emissions under actual economic, weather, and other conditions, with the percentage change or movement towards target emissions used as an indicator of progress.

Emission targets, specified in terms of percentage improvement and a maximum reasonable expected incremental cost that the utility may pay for emission reductions, may be based on analysis of the costs and emission impacts of alternative resource plans. Such analysis should consider alternative utilization of existing resources, as well as resource additions. Performance standards could function as a "soft" cap on utility system emissions, meaning that the utility would not be expected to implement emission-reduction measures with an incremental cost higher than a predetermined limit. Specification of a maximum reasonable expected incremental cost guideline can help ensure that costs incurred in response to environmental incentives remain within prudent bounds. Utility management would then be free to implement measures if the expected incremental cost per ton of additional emission reduction, in comparison to the next less stringent measure, was below the maximum cost target. Prudence, of course, should be measured based on reasonably expected costs at the time the decision was made (and any mismanagement in implementation), not on second-guessing utility decisions based on after-the-fact results.[36] Consistent application of this practice in environmental cases is particularly important because of the potential volatility of incremental costs, which depend not only on the cost of the measure selected, but also on the cost and potential performance of each less stringent alternative for reducing the specific emissions in question.

Financial incentives (or disincentives) could be based on annual progress toward CO_2 stabilization or some other specified emissions target appropriate for the utility and the conditions in which it may be operating. Incentives (and disincentives) may be set at specified amounts based on a fraction of the estimated value of potential environmental benefits or deferred future control cost. This relatively simple approach could provide the utilities an economic incentive to meet broadly accepted targets with respect to greenhouse gases or other emissions. If such programs and other voluntary efforts do not succeed, it is quite possible that some form of mandatory greenhouse gas controls will be enacted. The potential for recognition of reductions in future greenhouse gas or other emission-control programs, reduces any competitive disadvantage which might result form early action. A performance incentive could encourage the utility to act in a manner similar to market-based

[36] Robert E. Burns et al., *The Prudent Investment Test in the 1980s* (Columbus, OH: The National Regulatory Research Institute, April 1985).

approaches and, consequently, result in lower costs of control than rigid mandatory emission standards. Moreover, to the extent offsets from other sectors may be recognized, such standards could approximate the impacts of broader market-based environmental regulation. As electricity markets become more competitive, performance standards implemented at the pool (unit commitment and dispatching) level could become a central policy tool for achieving environmental resource diversity and other energy policy objectives without requiring regulatory approval of market transactions.

Green Pricing

Green pricing permits environmentally-oriented customers to pay a premium in return for additional investments in renewable or other environmentally benign resources. Experiments with this approach are currently underway in the Sacramento Municipal Utility District, where customer contributions are used to pay for photovoltaic units installed on customer rooftops, and at Public Service of Colorado, where premiums are contributed to a fund that supports the development of renewable resources. Soon (within the next few months) a municipal utility in Traverse City, Michigan is expected to begin a similar program in which customers paying a premium rate will support the cost of a wind farm designed to meet their annual generation requirements.

A number of principles have been articulated to frame the structure of green pricing experiments:[37]

- Green pricing must be a service that appeals to customers and to utilities. It permits differentiation between customers who do and do not wish to support additional environmental activities.

[37] David Maskowitz, *Renewable Energy: Barriers and Opportunities; Walls and Bridges* (Gardener, ME: Regulatory Assistance Project, July 1992).

- Green pricing should be simple and easily understood by customers.
- The utility's obligation under green pricing should be easily monitored and enforceable. It should require the utility to take measures over and above what would be reasonably required under IRP procedures.
- Green pricing programs should be both easy to administer and consistent with existing regulatory mechanisms.
- Appropriate safeguards should be incorporated to ensure proper use of revenues for previously specified measures.
- Green pricing should not disadvantage nonparticipating customers or utility shareholders.
- Green pricing should not be viewed as a charity but should be tied to the actual purchase of additional renewable resources.

Where green pricing has been explored through customer focus groups, customer response has been positive. However, designing an effective green pricing program can be difficult. First, the various parties must agree that the program does not duplicate what should occur through least-cost resource acquisition or through environmental regulation. Because environmental quality is a public good, green pricing should not be seen as a substitute for other environmental regulations or consideration of externalities. Second, the program must generate sufficient funds to produce identifiable purchases of significant renewable resources that can be difficult to accomplish.[38] Moreover, while customers may respond positively in a survey or focus group, they may not respond similarly in "real life" (that is, when the result is a higher electric bill).

Developing a Comprehensive Framework for Considering and Internalizing Environmental Costs

[38] Robin J. Walther, "Green Pricing for Renewable Resource Development: An Idea Whose Time is Coming?" *Proceedings of the 1993 Conference on Demand-Side Management and the Global Environment* (Bala Cynwyd, PA: The Conference Connection, June 1993), 17.

The tools for utility regulators discussed in this section can be used in combination to develop a well-grounded comprehensive framework for internalizing key environmental costs. Damage studies covering readily identifiable impacts may be used to identify a floor for estimates of environmental costs. These estimates can inform analysis of the tradeoffs between economic costs and environmental impacts for alternative resource plans. Based on such analysis, utility regulators could select environmental improvement targets and estimate the incremental costs required to achieve these targets. Such targets and incremental cost estimates could be used in setting the targets and cost limits used in establishing performance standards to internalize key environmental costs for particular utility systems. Additionally, green pricing could capture additional value for environmentally-oriented consumers by allowing them to subsidize the added incremental cost of higher-cost measures. Such an approach is not a substitute for comprehensive, market-based environmental regulation designed to limit emissions from both utility and nonutility sources. Given coordination with environmental regulators, such an approach could become an effective supplement to the development of market-based environmental regulation. Performance standards and green pricing may offer the flexibility to test the availability and effectiveness of low-cost emission-reduction strategies before broader mandatory reductions are required. The combination of the approaches discussed in this section may provide the means and incentives for identifying and capturing low-cost improvements in environmental quality. It also ensures credible entity level tracking of changes in emissions from a base-line path, which could provide the basis for receiving credit for past voluntary actions in any future mandatory control program. A careful and well-grounded approach could help make environmentally responsible strategies the utility's least-cost plan for meeting customer energy-service requirements.

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CHAPTER 4

PUBLIC UTILITY COMMISSION ACTION ON ENVIRONMENTAL EXTERNALITIES

By 1992, utility regulators in forty-one states had implemented IRP. In thirty-one of these states, regulators are considering environmental externalities in the resource planning or resource acquisition process. Thirteen of these states reported that externalities are either explicitly quantified and included in economic tests (eight), considered on both a qualitative and quantitative basis (eight, with overlap of four), or considered quantitatively through the internalization of the risk of future environmental regulation (one).[1] This chapter examines the approaches taken in a sample of states and the rationales for their diverse policy choices.

The development of RP reviews was partly a natural progression from the reviews of utility forecasts and facility siting during the 1970s. It often reflected a desire to avoid the type of controversy generated by the completion of expensive capacity additions during the 1980s. In some cases, the consideration of residual environmental impacts for which no economic cost was attached by environmental regulation was a logical result of applying benefit/cost analysis, which sought to quantify the total cost of alternate resource options. In other cases, environmental externalities were considered in order to meet narrower objectives, such as prudent anticipation of likely future environmental regulation or consideration of environmental factors which would be raised in siting proceedings.

The consideration of externalities is intended to address economic inefficiencies created by the failure of existing environmental regulation to internalize environmental costs and to recognize such potentially lower-cost means of limiting emissions such as

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[1] NARUC, *Utility Regulatory Policy in the United States and Canada* (Washington, D.C.: NARUC, 1993), 420.

changing the mix of generating resources or instituting conservation programs. The consideration of externalities in resource planning or acquisition, however, has more limited impacts than the actual internalization of environmental costs. Unlike an emission tax, the shadow prices of environmental adders are not costs to the sources of emissions. This typically has limited consideration of externalities to the planning or acquisition of new resources where such decisions are subject to explicit commission review. Consideration of externalities has not yet been extended to unit commitment and dispatch or other aspects of utility operations. Moreover, the dynamic incentives to reduce emissions at lower costs that can be created by an actual emission tax will most likely not develop as a result of commission consideration of externalities in resource planning. Nevertheless, over time, consideration of environmental externalities in resource planning could have an impact on the selection of new resources, life extension of existing units, and, as a result, utility costs, prices, and emissions.[2]

To examine how externalities are treated in utility resource planning, this chapter profiles practices in eight states, including four that have and four that have not established quantified monetary or percentage externality valuations. The states reviewed that have not adopted quantified valuations are: Virginia, Ohio, Maine, and Connecticut. The states reviewed that have developed specific quantified valuations are: Vermont, Wisconsin, Massachusetts, and New York. As summarized in Table 4-1, each of these states has adopted a somewhat different position and has been motivated by different policy

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[2] See Frances P. Wood, "Analyzing the Effect of Including Environmental Externalities in Utility Planing," *Proceedings of the ACEEE 1992 Summer Study on Energy Efficiency in Buildings* (Berkeley, CA: ACEEE, August 1992), 9.223; Daniel Bloyer and Michael Bull, "Least Cost Planning at the Margin: Externalities vs. Rate Impacts," *Proceedings of the ACEEE 1992 Summer Study on Energy Efficiency in Buildings* (Berkeley, CA: ACEEE, August 1992), 9.33; and Stephen Bernow and Donald Marron, "The Inclusion of Environmental Goals in Electric Resource Evaluation: A Case Study in Vermont," eds., E. Vine, D. Crawley, and P. Centolella, *Energy Efficiency and the Environment: Forging the Link* (Berkeley, CA: ACEEE 1991), 249.

considerations. The differences in approaches and concerns among the states reflect the richness of the debate regarding externality consideration. Virginia and Ohio opted for qualitative consideration, but for different reasons. In Maine, the state

TABLE 4-1

SUMMARY OF EXTERNALITY POLICIES IN SELECTED STATES

State	Externality Policy	Primary Policy Rationale
Virginia	• Qualitative consideration of environmental factors • Quantitative consideration of environmental impacts in demand-side management (DSM) benefit / cost evaluation is statutorily prohibited	• Statutory requirement that rates be based on the actual cost of providing service • Uncertainty and controversy regarding externality valuation • Commission's lack of environmental expertise
Ohio	• Qualitative consideration of environmental impacts in IRP • Quantitative consideration of Clean Air Act compliance costs in IRP • Dispatch based on SO_2 allowance costs	• Initial priority is Ohio's substantial Clean Air Act compliance costs • Lack of reliable data on externality valuation
Maine	•Further study of mechanisms to internalize environmental costs into energy prices and state decision-making processes •Further consideration of market-based environmental regulation	• Need to consider relationship between environmental and utility regulation • Lack of reliable externality valuations • Externality valuation unlikely to have a significant impact on near-term resource acquisition • Limited Commission resources
Connecticut	•Multiattribute trade-off analysis comparing emissions and economic costs of various resource options	• Provides flexibility to balance competing objectives, consistent with quantification to the extent accurate data is

TABLE 4-1

SUMMARY OF EXTERNALITY POLICIES IN SELECTED STATES

State	**Externality Policy**	**Primary Policy Rationale**
	•Environmental impacts are quantified but value not monetized •Reasonably certain anticipated costs of future regulation are considered	available • Better method for evaluating resource options under uncertainty • Identifies extent to which large emission reductions can be achieved at minimal cost
Vermont	•Rebuttable presumption of 5 percent adder on supply side resources for unpriced environmental impacts •Rebuttable presumption of 10 percent downward adjustment to DSM costs for lower risk •Public Service Board is also Vermont's energy facility siting board	• Statutory requirement to consider environmental costs in IRP • Adder and discount presumptions provide quantitative rules of thumb that replace implicit working assumption of zero cost or benefit
Wisconsin	•Monetized valuation of greenhouse gas emissions ($15 per ton CO_2) in Advance Plan proceedings •Advance Plans must use best available qualitative and quantitative methods to consider environmental factors	• Prudent anticipation of future regulation, builds on positive experience from state acid rain law • Captures all economic costs • In facility-specific IRP or competitive bidding proceedings, statute precludes consideration of those externalities subject to state air quality regulation
Massachusetts	•Externalities must be monetized to the greatest extent possible in bid evaluation for new	• Allow comparison of the social costs of resources offering different prices, environmental

TABLE 4-1

SUMMARY OF EXTERNALITY POLICIES IN SELECTED STATES

State	Externality Policy	Primary Policy Rationale
	resources and life extensions •Implied valuations based on control costs: SO_x--\$1,700 per ton; NO_x-- \$7,200 per ton; total suspended particulates (TSP)--\$4,400 per ton; VOCs--\$5,900 per ton; carbon monoxide (CO)-- \$960 per ton; CO_2--\$24 per ton; Methane (CH_4)--\$240 per ton; and nitrous oxide (N_2O)--\$4,400 per ton •Off-site emission reductions purchased through SO_2 allowance or NO_x or VOC offset programs recognized in estimating emissions	impacts, and nonprice characteristics • Ensure more complete valuation of environmental impacts than available damage cost assessments • Encourage development of market-based systems of environmental regulation, without determining whether allowance and offset programs fully internalize environmental costs
New York	•Estimates of environmental mitigation costs are used to compare resources in competitive bidding and DSM benefit/cost analysis: SO_x .25¢ per kilowatthour (kWh); NO_x .55¢ per kWh; CO_2 .1¢ per kWh; particulates .005¢ per kWh; water impacts .1¢ per kWh; land use .4¢ per kWh (1992 dollars)	• Establish a level playing field among alternative resources in bid evaluation, externality values are translated into points for ranking bids • Reflect environmental benefits of demand-side resources • Pursue a long-term strategy to improve methodologies for consideration of externalities

TABLE 4-1

SUMMARY OF EXTERNALITY POLICIES IN SELECTED STATES

State	**Externality Policy**	**Primary Policy Rationale**
	•On-going investigations and / or multiparty studies of policy and methodological issues, damage cost assessment, and total cost dispatching	

Source: Authors' construct.

legislature and the Commission have had a constructive dialogue regarding externality valuation and its relationship to environmental regulation. Connecticut recently opted for a new approach--multi-attribute trade-off analysis--designed to identify robust resource options under conditions of uncertainty and provide regulators flexibility in comparing incremental costs and environmental benefits associated with specific options. Vermont developed a percentage adder / discount approach as rebuttable presumptions to avoid making, in the absence of better data, the assumption supply side resources have zero environmental costs. Wisconsin adopted monetized values for greenhouse gas emissions in "prudent anticipation" of future regulation. Massachusetts and New York set monetized values for several pollutants. Additionally, Massachusetts takes into consideration off-site emission reductions under new market-based systems of environmental regulation. New York is undertaking a broad five-track investigation regarding how to value and consider environmental impacts.

Virginia

In a generic proceeding regarding the evaluation of conservation and load management programs, the Virginia State Corporation Commission (VCC) decided that the analysis of DSM options should not include quantification of externalities.[3] The VCC pointed out that it gives qualitative consideration to environmental factors and that environmental factors are analyzed during the approval of construction of major utility facilities. The VCC found that it lacked statutory authority to go beyond the consideration of environmental factors in approving construction certificates and qualitative consideration of environmental impacts.

With respect to its statutory authority to promote conservation and the effective use of energy, the Commission cited the Virginia Code §56-235.1:[4]

> . . .that nothing in this section shall be construed to authorize the adoption of any rate or charge which is clearly not cost-based or which is in the nature of a penalty for otherwise permissible use of utility services.

The VCC also referenced Virginia Code §56-235.2, which requires that rates in the aggregate not exceed actual costs incurred in serving customers within the jurisdiction of the VCC and prohibits speculative adjustments to such costs.[5] The VCC deemed the quantification of externalities to be speculative. It also noted that incorporating some externalities, but ignoring the impact of others could distort the balancing process and lead to economic inefficiency. It found that Congress and the General Assembly are the proper

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[3] *In re Investigation of Conservation and Load Management Programs,* Case No. PUE900070, Final Order (March 27, 1992), 12-14.

[4] Code of Virginia Annotated (Va. Code Ann.) §56-235.1.

[5] Ibid.

bodies to provide the broader perspective necessary for consideration of environmental factors.[6]

The VCC staff cites a number of factors which may have contributed to the VCC's decision including the lack of environmental regulatory expertise at the Commission, uncertainty and controversy regarding externality valuation, and the failure of any of the parties to the proceeding to suggest a means to quantify externality values. This 1992 decision is viewed by the staff as closing the door on future quantitative considerations of externalities outside facility certification proceedings. It should be noted that although Virginia utilities file resource plans every two years, those plans include qualitative discussions of environmental issues and are reviewed by the Commission staff, the plans are not subject to hearing or approval by the VCC.

During the last two years there has been increased communication between the VCC and state environmental regulators. Staff from the Department of Natural Resources now appear before the Commission in construction certificate proceedings.[7]

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[6] Ibid.

[7] Robert L. Lacy, Virginia State Corporation Commission, Personal Communication with author, January 13, 1994.

Ohio

The Public Utilities Commission of Ohio (PUCO) has devoted attention to Clean Air Act compliance costs, but has not developed monetary valuations for any remaining externalities. In the review of utility IRPs, the Commission considers a broad range of factors in determining the reasonableness of utility resource plans, including, "environmental impacts of the plan and their associated costs."[8] Other factors considered include the adequacy, reliability, and cost-effectiveness of the plan; whether DSM and nonutility generation have been evaluated in a manner consistent with other electricity resource options; uncertainty; potential rate and bill impacts; significant economic impacts and their associated costs; impacts on the financial status of the utility; strategic considerations including flexibility, diversity, the size and lead time of commitments, and lost opportunities; equity among customer classes; and impacts of the plan over time.[9] The Commission staff testified in one case that environmental externalities should be reviewed in an IRP proceeding to more accurately determine the full cost of each resource and ensure selection of the resource that would minimize the costs to society.[10] The staff testimony supported establishing a monetized values for CO_2, SO_2, NO_x, acid deposition, particulates, CO, VOCs, toxic materials, aquatic impacts, and noise, on a cents-per-kW basis. The testimony also supported qualitative discussion of water pollution and land use.[11] The implementation of these policies, however, has not led to quantitative consideration of externalities, except to the extent that some former externalities are being internalized through newly enacted environmental requirements.

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[8] Ohio Administrative Code §4901:5-5-03 (1989).

[9] Ibid.

[10] Prepared direct testimony of Klaus Lambeck, *In the Matter of the 1990 Long-term Forecast Report of the Monongahela Power Company*, Case No. 90-418-EL-FOR (October 29, 1990), 8-11.

[11] Ibid.

For purposes of evaluating DSM programs under a total resource cost test, the PUCO directed electric utilities in their 1992 IRPs to take into consideration externalities "expressed in terms of the control costs associated with the supply resources which would be avoided as a result of the DSM programs under evaluation."[12] In their filings, utilities reported projected control costs associated with the SO_2 provisions of the 1990 Clean Air Act Amendments, expressed in average compliance costs per kWh. Although the utilities did not quantify values for the other externalities listed in the Commission's order, the PUCO staff found that they had made reasonable progress by including in their DSM evaluations Clean Air Act compliance costs.[13]

The PUCO has been aggressive in reviewing utility Clean Air Act compliance. It has undertaken reviews of compliance plans both in IRP proceedings and in separate environmental compliance plan cases under a new Ohio statute.[14] The PUCO directed utilities to take SO_2 allowance costs into consideration in planned unit commitment[15] and dispatching, and adopted policies supporting prudent utility participation in allowance trading.[16]

The Commission has not required utilities to undertake studies to quantify values for environmental factors other than SO_2 compliance costs. It is these other residual emissions that would typically be considered to be environmental externalities. The

[12] *In the Matter of the 1992 Long-term Forecast Report Filing Requirements for Ohio Electric Utilities*, Case No. 91-2011-EL-FOR, Entry (November 21, 1991), 2.

[13] Klaus Lambeck, PUCO Staff, Personal Communication with author, January 13, 1994.

[14] Ohio Revised Code, Chapter 4913.

[15] *In the Matter of the Long-Term Forecast Report of the Ohio Power Company*, Case No. 90-660-EL-FOR (Phase II), Opinion and Order (September 24, 1991), 23.

[16] *In the Matter of the Commission's Investigation into the Trading and Usage of , and the Accounting Treatment for, Emission Allowances by Electric Utilities in Ohio*, Case No. 91-2155-EL-COI, Entry (January 20, 1993), 1-6.

primary reason given by the Commission staff for not requiring such studies is the lack of reliable data. The staff indicated that it is possible to quantify and verify projected control costs, but there is little reliability or certainty regarding information concerning environmental damages from other pollutants. Other factors cited by the staff include wanting to see the results of Clean Air Act compliance before requiring consideration of additional environmental factors and the cost of externality valuation studies.[17]

Maine

To date, the Maine Public Utilities Commission (Maine PUC) has not adopted valuations for externalities in its reviews of utility resource planning, competitive bidding, or other proceedings. The consideration of externalities, however, has been the subject of a series of legislatively mandated studies. In the current session of the legislature, legislation is pending that could lead to the development of externality valuations. The Commission already has broad legislative authority that might be construed to allow adoption of externality valuations, but the Commission's authority is not explicit.

In 1989, the legislature charged the Maine PUC with analyzing the extent to which environmental and economic impacts should be included in the electric utility least-cost planning process. The resulting 1991 report recommended that externality adders should not be adopted at that time. However, the report concluded that:

> We believe that, over the longer term, the use of externality value approaches may offer significant advantages over the current reliance on command-and-control techniques of environmental management. Therefore, we recommend continued participation by the Commission in national and regional forums and groups that are exploring this issue . . .. We also suggest that the legislature consider whether the

[17] Klaus Lambeck, PUCO Staff, Personal Communication with author, January 13, 1994.

> state's utilities should, if it can be done at reasonable cost, apply some of the research currently being undertaken for New England as a whole, to Maine specifically.[18]

The majority of the Public Utilities Commission who believed that externality valuation should not be adopted, cited the following factors:

> The interplay between existing environmental regulation and the least-cost approach has not been thoroughly explored. In fact, it has generally been ignored, and as a result the definition and treatment of externalities currently being used are inappropriate.
>
> Existing externality values are, for the most part, based on inadequate conceptual foundations, and vary so widely that they have very little reliability. Unless the values used for externality analysis truly reflect unaccounted-for externalities, properly valued, their use will detract from least-cost planning, not add to it. No values that purport to be relevant to Maine exist at the present time, and a considerable effort would be required to develop plausible estimates.
>
> . . .[I]t appears that for the short and intermediate terms (for example, this decade) an externality approach in least-cost planning would be unlikely to have a significant impact on resource planning in Maine. First, Maine is already a leader in developing environmentally responsible resources. Second, few new resources are likely to be coming on line beyond what is already committed for. Third, any new resources selected are likely to be the more environmentally beneficial ones in any event.
>
> At the present time (and for the foreseeable future), the Public Utilities Commission itself does not have sufficient

[18] *Environmental and Economic Impacts: A Review and Analysis of its Role in Maine Energy Policy* (Augusta, ME: Maine Public Utilities Commission, May 1, 1991).

> staff or financial resources to undertake the work that will be necessary to resolve the questions raised so far and / or to implement such major changes to utility resource and environmental planning processes.[19]

In the Commission report it was also observed, "Without substantial and careful coordination with other environmental agencies in the state, there is likely to be redundancy, overlap, and duplication of function."[20] Recognizing that the imposition of adders could complicate rather than simplify environmental regulation, the Commission nevertheless suggested that the Legislature consider environmental adder or tax approaches in place of alternative state and local environmental regulation when there could be substantial benefits from simplification of the administrative process.

Following the submission of this report, legislation was adopted establishing a State Commission on Comprehensive Energy Planning. The commission included ten members of the legislature, the Chairman of the Public Utilities Commission, the Commissioner of Environmental Protection, the Commissioner of Conservation, the Public Advocate, the Commissioner of Transportation, and the Director of the State Planning Office. The Commission was charged with studying the environmental costs or externalities associated with various energy options.

The Energy Planning Commission did not fulfill this specific charge. It recognized that the valuation of externalities can be a difficult and subjective task. It expressed concern regarding how to give equivalent treatment to regulated and nonregulated energy sources, noting that energy taxes are regressive and can burden low-income consumers disproportionately. It also noted that imposing higher costs on regulated energy sources, and failing to address the unregulated energy arena, could promote unwanted fuel substitution with negative environmental impacts.

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[19] Ibid.

[20] Ibid.

The Commission recognized the availability of alternatives for addressing environmental externalities, including the use of market-based systems of environmental regulation and consideration of environmental externalities in utility resource planning. The Commission's report framed the issue as follows:

> The focus of the debate is whether unaccounted-for environmental impacts are more appropriately addressed through environmental policy and environmental regulation, whether these impacts should be considered in the energy planning process itself (for example, the least-cost planning and competitive bid process administered by the PUC), or whether some combination of both can be developed.[21]

The Comprehensive Energy Planning Commission's May 1992 report concluded that "Energy planning cannot go forward without recognizing that almost every energy strategy involves some degree of positive or negative environmental impact. Therefore, future energy strategies must be coordinated with state and federal environmental policies and regulatory mandates."[22]

The Energy Planning Commission found that addressing the environmental effects of energy production and use was a "fundamental objective of state energy policy," and that "Maine should incorporate unaccounted-for environmental costs directly into public policy and regulatory processes that affect Maine's energy future."[23] The Commission recommended the following:

> Maine establish a broad-based advisory group on Energy and the Environment to examine fully, in an ongoing manner, how

[21] *Final Report of The Commission on Comprehensive Energy Planning* (Auburn, ME: Maine State Planning Office, 1992).

[22] Ibid.

[23] Ibid.

> to develop and implement mechanisms to incorporate environmental impacts that are not already internalized in the price of energy and to the state's decision-making process. . .. The advisory group should be charged with:. . .
>
> (1) Identifying State environmental policies and needs affecting energy policy;
>
> (2) Assessing the effectiveness of existing State and federal environmental laws and regulations in implementing those policies; and
>
> (3) Determining options for reconciling any discrepancies between policies and existing laws and regulations.
>
> Options to be evaluated should include:
>
> (a) Strategies for including externalities in energy decision-making processes;
>
> (b) Changes to Maine environmental laws; and
>
> (c) Emission taxes and / or caps.[24]

The final report of the Commission was issued in May 1992, and expressed unanimous support for the goal of addressing the environmental effects of energy production. The report also expresses the Commission's belief that, "it is not so much a matter of whether, but when and how" externalities will be incorporated into Maine's least-cost planning process.[25] Following the Comprehensive Energy Planning Commission's report, three bills were introduced in the legislature in 1993 to address externality issues. One (L.D. 102) would add language to the Maine Energy Policy Act, making "environmental impact" an explicit factor to be considered in least-cost planning. Another

[24] Ibid.

[25] Ibid.

bill (L.D. 305) proposed similar but more extensive changes to the Maine Energy Policy Act and would require the Maine PUC to initiate a rulemaking to establish "weighting factors" to be used in resource selection. The third bill introduced (L.D. 356) would establish an advisory council on energy and the environment to carry out the recommendation of the Final Report of the Energy Planning Commission.

The Maine PUC supports L.D. 356, which seeks to establish the recommended advisory council. The legislature may vote on L.D. 356 in 1994. Concern regarding the availability of resources to address the externality issue continues to be a factor affecting the development of the advisory council.[26]

The externalities issue was raised in a 1993 case addressing Central Maine Power's resource planning, rate structures, and long-term avoided cost. Environmental intervenors (the Natural Resources Council of Maine, the Conservation Law Foundation, and the Coalition for Sensible Energy) proposed an "Ecowatts" test, which would allow pricing particular electric end uses to promote the choice of electricity over competing fuels, if electricity (1) is the most energy efficient alternative available regardless of fuel, (2) passes a total resource cost test including externalities, and (3) causes no adverse environmental impact. The Commission Examiners' Report stated that it was "intrigued" by this proposal because it would expand the current approach to least-cost planning and add symmetry to the debate over fuel switching. With respect to the task of quantifying externalities, however, the Examiners' Report commented that "contemplating that challenge can inspire both awe and humility." It encouraged parties to submit proposals for effective and efficient ways to consider environmental externalities in utility resource planning.[27] The

[26] Eric VonMagnus, Maine PUC Staff, Personal Communication with author, January 13, 1994.

[27] *In Re Investigation of Central Maine Power Company's Resource Planning, Rate Structures, and Long-Term Avoided Costs,* Docket No. 92-315, Examiners' Report (December 14, 1993), 60-63.

Commission's 1991 report indicates a clear preference that any future development of externality valuation should be undertaken based on damage cost assessment.

The Maine PUC is supporting an initial phase of preregulatory activity with respect to greenhouse gas emissions including the developing of an inventory of greenhouse gas emissions, an action plan, and demonstration projects. This activity is being supported by a federal grant. Additionally, the Commission has been following regional activity that could lead to the establishment of a NO_x cap.[28]

The Commission staff remains concerned about the cost and rate impacts that might be associated with consideration of environmental externalities. The staff is sensitive to the fact that Clean Air Act and Clean Water Act requirements already may impose significant costs on the state's economy.[29] The emergence of competition has led to discussions that additional environmental regulations on utilities, which are not shared by competitive alternatives, might lead to uneconomic bypass and higher emissions.

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[28] Eric VonMagnus, Maine PUC Staff, Personal Communication with author, January 13, 1994. See also the discussion of the NESCAUM NO_x cap proposal in Chapter 3.

[29] Ibid.

Connecticut

In December 1993, the Connecticut Department of Public Utilities Control (DPUC) adopted a trade-off approach to the consideration of environmental externalities. DPUC regulations specify that the Department is to consider likely environmental impacts in its review of resource proposals.[30] The DPUC always has considered environmental impacts qualitatively, approving wood, hydroelectric, and waste-to-energy projects that were not least-cost power supplies. In 1992, the legislature directed the DPUC to "conduct a study concerning the external costs and benefits associated with energy consumption" and, in particular, to "analyze the possibility of establishing a system of tradable allowances, offsets, fees or numerical adders to take into consideration the indirect costs associated with energy consumption when analyzing all new proposed resources.[31]" As a result of that mandate, the DPUC completed an investigation into the external costs and benefits of energy consumption.[32] In that investigation, some parties urged the Commission to adopt externality adders. The Department declined to do so, and instead adopted a tradeoff approach which would require comparisons of emissions and economic costs associated with different resource options. The appropriate weight to be placed on environmental considerations would then be decided on a case-by-case basis. Without being limited to uniform adder quantifications, the trade-off approach provides the Department greater flexibility and retains the DPUC's capability to exercise judgment regarding specific proposals.

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[30] Regulations of Connecticut State Agencies, §16-243a-3(b)(2), 1989.

[31] Connecticut Public Act 92-106.

[32] *DPUC Investigation of the External Costs and Benefits Associated with Energy Consumption*, Docket No. 92-09-29, Report to the General Assembly (December 30, 1993), 1.

The Department examined different approaches for valuing externalities and found both the use of damage cost assessment and control cost valuation to be inappropriate at this time.

> The Department considered several approaches to determine the value of external factors. One approach is the damage avoidance method, in which the value of the external factor is set equal to the presumed damages that are avoided by control measures. . .. While this approach is conceptually sound, the difficulty with acquiring reliable data often renders that method impractical. Another approach, the cost-of-control method, has readily available data, but it unfortunately measures only the cost of control, not the benefits of control. . .. [A]s it becomes increasingly expensive to eliminate smaller and smaller increments of pollution, the value of further reduction usually declines. Therefore, the Department concludes that the cost-of-control method is inappropriate as a measure of control benefits.[33]

The Department concluded that adders reflect the uncertainty of specific valuation methods and lead inevitably to piecemeal regulation. Instead, the Department adopted a tradeoff approach in which environmental effects might be quantified (for example, tons of emissions) but would not be monetized with specific valuations.

> The Department will instead implement a more flexible method of recognizing external factors. The best method for evaluating the need for action under uncertainty is a form of tradeoff analysis, which compares different strategies based on implementation costs and a quantified indication of results.
>
> . . .Such a measure does not specify in dollars what it would be worth to be rid of the harmful effects, but makes possible a comparison of the cost to attain different levels of pollution reduction. Tradeoff analyses identify options which might

[33] Ibid., V.

> offer large reductions in pollution for relatively low cost, and can lead to what has been called a "no regrets" result. Tradeoff analyses provide the advantages of quantification, to the extent that accurate data is available, and the flexibility to balance competing policy objectives.[34]

The Department found the tradeoff approach is preferable under conditions of uncertainty precisely because it does not assume a high level of precision with respect to cost estimates or damage valuation, provided that its limitations are kept in mind and data requirements remain manageable.[35]

The overall result of the Department's investigation was to implement the following four changes in its method of analyzing new energy resources:

- The Department will include in its analyses "prudently anticipated" costs of future regulation when the effects of future regulation are reasonably certain.
- Whenever possible and relevant, externalities will be quantified (although not monetized) to improve the subjective evaluation process already in use.
- In the specific context of new resources that are exempt from the bidding process and conservation programs, the Department may consider proposals with direct costs that exceed the strict definition of avoided cost, where corresponding external benefits exist.
- The Department will discontinue use of automatic and arbitrary adders in the evaluation of conservation projects and instead require more a thorough analysis of costs and benefits through tradeoff analysis.

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[34] Ibid., V.

[35] Ibid., 11-12.

The Department's report also discusses a number of potential externalities that will be specifically considered, including SO_2, NO_x, VOCs, particulates, carbon monoxide, air toxics, CO_2 and other greenhouse gases, fuel supply diversity, land use impacts, water impacts, electromagnetic fields (EMF), distribution system reliability, generation system reliability and risk, noise, visual impacts, cultural and historical impacts, capacity and demand risk, and economic development.

The DPUC's adoption of a tradeoff analysis approach reflects, in part, concern about competition and pricing impacts. As competitors who may not bear certain environmental costs enter power markets, the DPUC anticipates having to deal with difficult questions about who should absorb sunk costs.[36]

Additionally, the DPUC took the position that it should proceed cautiously in areas where environmental regulators have primary jurisdiction, pursuing the informal, cooperative approach of participation in the Interagency Clean Air Policy Committee (ICAPC). The ICAPC was formed in 1993 to coordinate Connecticut policy with respect to the implementation of the 1990 Clean Air Act Amendments. The DPUC would like to move in the direction of internalization of emissions cost through the establishment of a NO_x trading program and is working with the Department of Environmental Protection on such alternatives. In its recent report to the General Assembly, the DPUC "endorses the use of flexible, market-based control techniques such as tradable allowances, offsets and fees," concluding that "market-based techniques achieve the same levels of pollution reduction as more rigid "command-and-control" methods but impose a lower total cost of compliance."[37]

[36] George Dunn, DPUC Staff, Personal Communication with author, January 17, 1994.

[37] Ibid., VI.

Vermont

The Vermont Public Service Board (PSB) adopted rebuttable presumptions in favor of an environmental adder on supply side resources and a risk discount to conservation and load management costs. These presumptions alter the assumption of zero costs or benefits in the absence of better information.

The statutory role of the PSB is unique in two respects. First, the Board functions as both a ratemaking authority and the siting board for major energy facilities. In siting cases, the Board is specifically required to consider a broad range of environmental impacts.[38] These include water and air pollutants; impacts on floodways, shorelands, streams, and wetlands; impacts on water supplies; soil erosion potential; impacts on transportation, municipal, and educational services; impacts on aesthetics; effects on areas of scenic and natural beauty; impacts on rural and irreplaceable natural areas; effects on historic and archeological sites; considerations of necessary wild habitat and endangered species; impacts on agricultural soil; impacts on public investment; and impacts on outstanding water resources.[39] Additionally, Vermont law sets the criteria used to determine if new facilities are in the public interest; the criteria include whether proposed facilities may have undue environmental impacts.[40] Data on monetized environmental impacts has been presented in past siting cases and considered as one factor by the Board in its final decision as to whether pollution or other external impacts were "undue." Second, the statutory standards governing Vermont's IRP process require consideration of environmental costs. A least-cost IRP is defined in 30 V.S.A., §218(c) as a plan to meet the public's need for energy services at the best present value of life-cycle cost, including environmental and economic costs.

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[38] 30 VT State Ann. Tit. 30, §248 (1992).

[39] 10 V.S.A. §6086(a).

[40] 30 V.S.A. §248.

The Public Service Board addressed the issue of environmental externalities in its 1990 order establishing the framework for consideration of DSM and IRP. In that order, the Board distinguishes between supply side and demand-side investments, establishing a pair of rebuttable presumptions. First, the Board accepted a proposed 5 percent adder on supply side resources as an initial proxy for their unpriced environmental impacts. Second, the Board applied a 10 percent downward adjustment for reduced risk to the cost of DSM options. These adjustments are rebuttable presumptions which serve as "quantitative rules of thumb, to replace the previously implicit working assumptions of zero."[41] In future proceedings parties may argue for higher or lower values, but the Commission has made clear that evidentiary challenges to the presumption "must be rigorous."[42] The Commission justified its position on grounds that these adders and discounts would better reflect real environmental costs and the potential of DSM measures to reduce risk as a result of their flexibility, short lead time, and the increase in DSM opportunities with growth in load. The Attorney Examiner's report in the case recounted evidence regarding the 10 percent premium for efficiency options in the Northwest Power Planning Act, the development of externality cost valuations by the New York Public Service Commission, the 15 percent environmental premium which at that time was used by the Wisconsin Public Service Commission, and the effects of acid rain, greenhouse gas emissions, and other environmental impacts associated with electric generation.[43]

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[41] *Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy*, Docket No. 5270, Order (April 16, 1990), Vol. IV, 14-15.

[42] Ibid.

[43] *Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy*, Docket No. 5270, Hearing Officer's Report and Proposal for Decision (April 16, 1990), Vol. 3, 103-109.

The Commission has continued its investigation into environmental externalities with the view toward advancing its understanding of the issues and developing more accurate estimates of the unpriced environmental costs for different energy supply sources. On September 30, 1992, the Board opened a rulemaking proceeding to revisit its methodology for valuing externalities. The Board conducted negotiations through a series of informal workshops, with participation by representatives from utilities, state agencies, industry and nonprofit organizations. The negotiated effort was not successful, and the Board is currently proceeding with a contested case. In January 1994, the parties completed briefing of jurisdictional issues regarding the PSB's authority to consider environmental costs and its ability to consider environmental costs occurring outside the state of Vermont. In past cases addressing out-of-state power purchases, the Board took the position that it would consider impacts associated with in-state projects or environmental effects on the state associated with out-of-state purchases.

According to the PSB staff, the agency sees its role as allocating costs and risks associated with power production. One of the risks which utilities should consider is the fact that environmental impacts may be internalized in the future. Part of the Board's responsibilities, particularly because of its role in siting, has been to balance economic and environmental interests. Externality valuation is viewed as fulfilling the Board's responsibilities to allocate costs and management of risk.[44]

Coordination between the Agency of Natural Resources (ANR) and the PSB is growing. By statute, the ANR must now participate in all energy siting reviews. Additionally, there have been meetings involving the ANR and PSB regarding the implications of Title I of the 1990 Clean Air Act Amendments for Vermont's utilities.[45]

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[44] Michael Dworkin, Vermont PSB General Counsel, Personal Communication with author, January 11, 1994.

[45] Ibid.

Because Vermont is part of an integrated power pool, the PSB staff has considered effects of new Vermont resources on system-wide costs and emissions, but the appropriate approach for considering such impacts is currently unresolved.[46]

The position of the staff is that intersectoral effects related to users switching to other utilities or fuels as a result of externality consideration are not likely to be large because externality considerations have not produced major bill increases. The Staff is also aware that rate impacts might be significant when customers are comparing energy available from different utilities. Concern about bill and price impacts from the consideration of externalities, however, is mitigated by the fact that externality considerations reflect an assessment of the risk for future cost internalization and are designed to reduce likely total future costs.

[46] Ibid.

Wisconsin

The Wisconsin Public Service Commission (PSC) considers environmental externalities as part of an effort to consider external economic costs. Pointing out that the market reduces many, but not all, costs and benefits to monetary terms, the Commission concludes that incorporating environmental externalities into planning decisions is in the long-term best interest of the public and the utilities.[47] The Commission requires utilities in their Advanced Plan filings to use the best available qualitative and quantitative methods for considering environmental factors. However, with respect to the risk of future greenhouse gas regulation, the Commission established the following monetary values associated with emissions: $15 per ton for CO_2; $150 per ton for methane; and $2,700 per ton for NO_x. This does not reflect an estimate of *damages* but an estimate of *expenses* that are likely to be associated with future regulation of greenhouse gas emissions.

The Commission took the following position:

> Because of widespread concern about the risks of global warming at state, national, and international levels, future regulations are likely to require the utility industry to limit its release of these gases. If so, utilities would incur real economic costs to comply with these regulations.
>
> . . . A national and international consensus to regulate greenhouse gas emissions is emerging. In the likelihood of future regulation is high, it is reasonable to estimate the cost of compliance to utilities. Ignoring this financial risk would be imprudent.
>
> . . . Monetizing the risk of greenhouse gas regulation is a prudent means of reducing utility business risk, by hedging against the future. The Commission has exercised similar

[47] *Re Advanced Plans for Construction of Facilities*, Docket No. 05-EP-6, 136 PUR 4th 153 at 174-178 (September 15, 1992).

> foresight in other Advance Plans, to benefit the public and the utilities. Concerns about greenhouse gases resemble Wisconsin's earlier concerns about acid rain, which state government successfully addressed in the 1980s. The State's early response to acid rain has superbly positioned Wisconsin utilities to take advantage of the federal emissions allowance program. Monetization may do the same for utilities considering the likelihood of national or international greenhouse gas regulations.[48]

In the 1980s, Wisconsin adopted state acid rain legislation that reduced SO_2 emissions to a level at or below the levels mandated under the 1990 Clean Air Act Amendments. As a result, Wisconsin utilities have sold excess emission allowances (the proceeds are passed on to ratepayers).

The Commission currently does not monetize other externalities. This may be, in part, in response to litigation overturning an earlier 15 percent externality adder and statutory limitations which continued to be an issue in the Advance Plan 6 proceeding where greenhouse gas emissions were assigned a monetary value. The Wisconsin statutes related to the issuance of certificates of public convenience and necessity for new facilities include a specific limitation with respect to environmental standards. Wisconsin Statutes §196.491(d)(4) provides, in part, that:

> In its consideration of the impact on other environmental values, the Commission may not determine that the proposed facility will have an undue adverse impact on these values because of the impact of air pollution if the proposed facility will meet the requirements of [the state's air quality statutes].[49]

[48] Ibid.

[49] See also Wisconsin Statute §196.491(d)(3) (1980).

The legislative history of this provision, which predates the monetization of externalities, is that it was designed to prevent the Commission from requiring a facility to meet clean air standards which are more stringent than the standards approved for such a facility by the Department of Natural Resources.[50] The Commission's position is that it can monetize values with respect to greenhouse gases because: (1) greenhouse gases are not regulated by the Department of Natural Resources, and (2) Advance Plan proceedings are not part of the process for issuing certificates of public convenience and necessity. Entirely separate from the Advance Plan process, the Commission has initiated a two-stage competitive bidding, IRP process which leads to a certificate of public convenience and necessity. The Advance Plan proceeding determines general utility need and parameters related to fuel cost, DSM technologies, and other factors to be used in the competitive bidding, IRP process. The Advance Plan identifies the need for generic types of capacity, such as baseload, intermediate, or peaking but will not identify specific resources for acquisition. The evaluation of specific resources will occur in the two-part competitive bidding IRP process. The Commission Staff's current position is that it may not be able to use monetized values for greenhouse gas or other emissions in the competitive bidding IRP process because this process may result in the issuance of a certificate of public convenience and necessity.[51] Pending legislation would specifically authorize the competitive bidding IRP process and allow consideration of environmental externalities within that process.

The Commissionfinds damage cost assessment to be appealing but has not adopted such an approach because of the difficulty in getting a comprehensive assessment of environmental damages. Wisconsin utilities are working on a damage cost study, but the results of that study apparently will not be presented in the current Advance Plan 7

[50] *Re Advanced Plans for Construction of Facilities*, Docket No. 05-EP-6, 136 PUR 4th 153 at 174-178 (September 15, 1992).

[51] Paul Newman, Wisconsin PSC Staff, Personal Communication with author, January 17, 1994.

proceeding.[52] The Commission has said that any method chosen by the utilities should rely on currently available information, be flexible enough to readily incorporate new information, and be easy to understand, and that clearly identifying a method's assumptions and steps will aid in keeping the method understandable.

In Advance Plan 7 the Commission staff intends to focus on the consideration of other externalities which are not currently quantified, including nuclear externalities and toxic emissions. NO_x, SO_2, land and water impacts will continue to be looked at in a qualitative manner.[53]

In evaluating externalities, the Commission looks at the impact of resource additions on emissions from the utility system. For example, in Advance Plan 6, the Commission compared the addition of gas-fired units with atmospheric fluidized bed combustion coal units in the Wisconsin Electric system. The Commission concluded that clean coal-fired units would result in lower system-wide emissions, than the addition of gas units which by themselves would have lower emissions, but might be less fully utilized. While a reduction in the utility's need for new capacity has subsequently changed the utility's preference in favor of gas-fired units, this example illustrates the possibility that looking at net changes in system-wide emissions can lead to a different result than considering only the emissions from the new facility.

The PSC staff works on a regular basis with staff from the Department of Natural Resources (DNR). DNR has assembled an energy team which participates in the planning process, screening out bids for potential flaws and testifying in Advance Plan proceedings. Unlike the PSC, however, the DNR staff does not necessarily have an integrated perspective of energy issues. Air quality, water resources, and other DNR divisions take their own approaches to, for example, fossil fuel versus hydroelectric facilities and have

[52] Ibid.

[53] *Re Advanced Plans for Construction of Facilities*, Docket No. 05-EP-6, 136 PUR 4th 153 at 174-178 (September 15, 1992).

exhibited difficulty in developing a coherent position regarding how best to meet energy needs.[54]

Because of potential pricing and competitive impacts, the Commission may be concerned about the fact that it is quantifying externalities and other states are not. However, the record in the Advance Plan 6 case indicates that the monetized greenhouse gas values will likely increase electric rates only slightly, by about .25 percent per year.[55]

Massachusetts

The Massachusetts Department of Public Utilities (DPU) has a detailed integrated resource management (IRM) process for the review of utility resource plans and competitive bidding procedures. In the IRM process, bids received must be compared on the basis of total social cost, including environmental externalities. Externalities must be monetized to the greatest extent possible and added to the direct resource costs for the purpose of bid evaluation. The Department has adopted generic values to be used by all electric companies in monetizing certain air-pollutant emissions. In a 1992 decision, the Department authorized offsets to externality valuation for certain off-site emission reductions occurring under market-based systems of environmental regulation.

The Department's rationale for externality valuation is relatively straight forward--to ensure the selection of preferred energy resources.

> The purpose of estimating environmental externality values is to enable decision makers to compare, on a consistent basis, the social costs associated with alternative energy resources offering different prices, environmental impacts, and nonprice characteristics. To illustrate the value of externalities assume a situation where there are two generating facilities that meet

[54] Paul Newman, Wisconsin PSC Staff, Personal Communication with author, January 17, 1994.

[55] Ibid.

> federal emission limits and are alike in all respects (for example, price, reliability) except that one facility emits significantly less pollution than the other. Most would agree that the facility with lower emissions would be preferred. If the value of environmental externalities resulting from emissions permitted by federal statute were zero, we would be completely indifferent between these two generating facilities. Since we would not be indifferent--that is we would prefer the less-polluting generating facility--externalities must have an economic value that we need to consider in our resource choices.
>
> . . .The value of lower environmental externalities associated with a cleaner resource would equal the maximum difference in price between two resources (where the price of the dirtier resource is lower than the price of the clean resource) that would be acceptable before society preferred the dirtier resource. In theory, before society opts for the dirtier resource, the difference in prices (and presumably the cost) between the dirtier and cleaner resources (that is, the amount by which the dirtier resource is lower than the cleaner resource) must be greater than the value of the incremental environmental damages associated with the dirtier resource relative to the cleaner resource.[56]

Externality valuations are considered only in the resource planning process, which encompasses purchase or construction or new resources and life extension of existing facilities. The Department has not considered applying such values to unit commitment and dispatch or other aspects of utility operations.

Externalities are to be applied in all electric company filings involving resource cost-effectiveness tests. This has included preapprovals of utility DSM and generation programs, qualifying facility proposals, purchase power agreements, and third party DSM

[56] *Investigation by the Department of Public Utilities on Its Own Motion Into Proposed Rules to Implement Integrated Resource Management Practices for Electric Companies in the Commonwealth*, Docket No. 89-239, Opinion and Order (August 31, 1990), 61-62.

contracts. The Commission is moving toward including all of these resource acquisition activities into a uniform IRM process.

In a December 1989 Order,[57] the Department first indicated its commitment to require each electric company to consider environmental externalities in the resource selection process. The Department held that significant impacts to humans, the natural environment (for example, wildlife, habitat, plants), and the built environment (for example, buildings, statues, machinery) should be considered regardless of whether those impacts occur within Massachusetts or elsewhere. At that time, the Department suggested a ranking and weighting approach and requested comments on three such methodologies.[58]

Following the comments received in response to its 1989 Order in Case No. 89-239, the Department chose to establish a uniform set of monetized values for externalities:[59]

> The Department finds that effective weighting and ranking approaches could be designed to account for the variation in environmental impacts among various energy resources. However, in order to design an effective weighting and ranking approach, environmental impacts and the value of those impacts would have to be estimated so that appropriate weights could be determined. If weighting and ranking systems require quantification of externality values in order to determine the appropriateness of the weights, forming weights becomes unnecessary because the quantified externality values could be monetized and added directly to project costs to assist

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[57] *Investigation into the Pricing and Ratemaking Treatment to be Afforded to New Electric Generating Facilities Which Are Not Qualifying Facilities*, Case No. D.P.U. 86-36-G, Opinion and Order (December 6, 1989), 77-96.

[58] Ibid.

[59] *Investigation by the Department of Public Utilities on Its Own Motion Into Proposed Rules to Implement Integrated Resource Management Practices for Electric Companies in the Commonwealth*, Docket No. 89-239, Opinion and Order (August 31, 1990), 51-85.

> in the determination of the mix of resources that minimizes cost and environmental impacts simultaneously.
>
> Accordingly, the comments in this proceeding convinced the Department that externalities should be monetized to the greatest extent possible and that such values would be added to direct resource cost (that is, price bids of proposed resources, and the avoidable costs of existing and planned resources) for the purposes of evaluating and comparing alternative energy resources. . .
>
> As we stated in DPU 86-36-G, the Department realizes that monetizing externality values does not constitute the elimination of subjective judgments in the evaluation of externalities. We expect that as externality values are proposed by utilities and interested parties for use in the IRM process, the proponents of such values will reveal all assumptions and judgments so that their merit can be discussed in an appropriate public forum.[60]

The Department concluded that qualitative environmental externality systems (for example, weighting and ranking) only obscure implicit valuation and judgements. The Department also found that, ideally, the costs of externalities associated with the entire fuel cycle should be included in the resource evaluation process.[61] However, the Department determined that priority should be placed on estimating externalities that are the direct result of power plant operation including all "downstream" effects (for example, solid waste disposal), and directed companies to consider all impacts resulting from power plant operation, including air, water, solid waste and spent fuel disposal impacts, and resource use. The Department decided at that time to not include site-specific impacts, because proposals could be made in the IRM process without an actual project site being established

[60] Ibid., 58-60.

[61] Ibid., 77-79.

and the siting process in Massachusetts specifically evaluates site impacts. Similarly, valuation of "upstream" (before power plant operation) fuel-cycle impacts was not required due to a lack of information and because such impacts also included, to some degree, site-specific impacts. The Department stated that, as externality valuation experience increased, it would consider expanding the scope of externality valuation to include those associated with earlier stages of the fuel cycle.

The Department also concluded that damage valuation would be preferable for externality valuation. However, the Department to date has relied upon values derived using the implied valuation (IV) method for specific pollutants because: (1) the Department believes that marginal control costs reflect the implicit value society, in aggregate, places on marginal emissions; (2) the Department believes that the values that result from the IV method are likely to underestimate the damages that result from pollutant emissions; and (3) damage valuation estimates presented before the Department have been incomplete, have not been accompanied by a clear presentation of the valuation method and judgements applied, and have been dependent upon assumptions that are not supported by the weight of scientific evidence.

In November 1992, the Department reaffirmed the externality values adopted in Case No. 89-239.[62] In its 1992 decision, the Department reviewed both damage valuation and implied valuation methodologies. This issue was extensively litigated. The Department found that the proposed damage valuation approaches failed to meet criteria of comprehensiveness (addressing all important effects of emissions) and reliability (having a basis and a clear and explicit presentation of method, data, calculations, judgements, assumptions, variability and uncertainty in the results). In particular, the Department

[62] *Investigation by the Department of Public Utilities on Its Own Motion as to the Environmental Externality Values to be Used in Resource Cost-Effectiveness Test by Electric Companies Subject to the Department's Jurisdiction*, Case No. 91-131, Opinion and Order (November 10, 1992), 41-43.

found that neither the scientific community in general nor the EPA had established or endorsed the positions taken by the utilities' damage cost experts. The positions were: (1) there is a threshold for human health effects of criteria pollutants (SO_2, NO_x, VOC, O_3, particulates, CO, and lead) at concentrations at or near the NAAQS; or (2) there is a dose-response relationship for human health effects of criteria pollutants at concentrations close to the NAAQS that is only a fraction of those effects experienced in locations or periods of higher pollution concentrations. The Department also found that the utility witness' estimates of the economic impact of global warming on the U.S. did not provide a sufficiently comprehensive estimate of potential climate change damages.

Expressed in 1992 dollars, the specific monetized values adopted for externalities in Case 91-131[63] are shown in Table 4-2. Following the adoption of air toxic standards by the U.S. EPA and the Massachusetts Department of Environmental Protection (DEP), the DPU may consider establishing values for air toxics. The Order did not establish values for water use, land use, and ash disposal, based on a lack of sufficient evidence that these impacts are not local and / or accounted for adequately in the siting process.

The Department's 1992 Order limits the applicability of some externality valuations based on a recognition of off-site emission reductions. The Department's recognition of offsets for off-site emission reductions is designed to avoid interference with the operation of the Clean Air Act SO_2 allowance market and NO_x and VOC offset trading markets during their initial stages of development. In January 1993, the Massachusetts DEP proposed an interim rule on Emission Reduction Credit banking and trading for NO_x and VOC emissions. The DPU policy supports the development of market-based mechanisms for achieving society's environmental objectives and recognizes that market-based mechanisms have the potential to be more economically efficient in attaining

[63] Ibid., 56-79.

environmental goals than traditional "command-and-control" environmental regulation. As a result of the DPU's decision, project proponents are not required to

TABLE 4-2 MASSACHUSETTS DPUC EXTERNALITY VALUES	
Externality	**Mitigation Cost ($/Ton)**
Sulfur Oxides	1700
Nitrogen Oxides	7200
Total Suspended Particulates	4400
Volatile Organic Chemicals	5900
Carbon Monoxide	960
Carbon Dioxide	24
Methane	240
Nitrous Oxide	4400

Source: *Investigation by the Department of Public Utilities on Its Own Motion as to the Environmental Externality Values to be Used in Resource Cost-Effectiveness Test by Electric Companies Subject to the Department's Jurisdiction*, Case No. 91-131, Opinion and Order (November 10, 1992), 56-79.

apply an externality value to any ton of emissions for which they will be required to hold an SO_2 allowance or an offset for NO_x or VOCs pursuant to provisions in the Clean Air Act. However, the Department was not willing to conclude that the 1990 Clean Air Act Amendments had the effect of "internalizing" such emissions. This, in part, reflects the fact that the Title IV SO_2 allowance system is intended to address only the acid deposition impacts of SO_2 emissions.

In Case No. 89-239, the MIT Energy Lab argued against monetization and in favor of a multi-attribute tradeoff analysis approach. Their argument was based in part on studies that indicated that demand-side resources might perform poorly, relative to some supply side alternatives with higher capacity factors, in reducing SO_2, NO_x, and particulate emissions. The Lab argued that the impact of a given resource on system-wide emissions might be different from the pollutants emitted by the incremental resource. The Department addressed this criticism by directing utilities in their bid evaluation to conduct an optimization analysis to examine interactive effects, including the interaction between new and existing resources, and to examine the environmental impacts of various combinations of proposed and existing resources. It is the D.P.U. staff's position that utilities can accurately conduct this optimization with respect to their own dispatch and should be able to identify impacts associated with the integrated dispatch in the NEPOOL power pool.[64]

In Case No. 90-141, involving the application of externality valuation to Eastern Edison Company purchases, the Department recognized the benefit of a regional approach to valuing externalities but held that regional consensus was not a necessary condition to the application of monetized values.[65]

[64] *Investigation by the Department of Public Utilities on Its Own Motion into Proposed Rules to Implement Integrated Resource Management Practices for Electric Companies in the Commonwealth,* Docket No. 89-239, Opinion and Order (August 31, 1990), 57-58.

[65] *Investigation into the Filing Made by Eastern Edison Company*, Case No. D.P.U. 90-141, Opinion and Order (June 14, 1991).

The 1989 Order in Case No. 86-36-G also indicated that the Department and the DEP were discussing coordination of issues related to the interaction of all-source bidding and DEP permitting requirements. In April 1990, the Department of Public Utilities, the Department of Environmental Protection, the Energy Facility Siting Council, and the Massachusetts Environmental Policy Act Unit of the Executive Office of Environmental Affairs entered into memoranda of understanding which, in part, provided the following:

- During the comment period for competitive bidding RFPs, the DPU will request from the DEP a guidance statement regarding currently accepted baseline regulatory standards for emissions and resource use. All proposals will be required to incorporate price and nonprice terms reflecting at least compliance with the DEP standards set forth in this guidance document.
- Each agency will circulate to the other agencies for comments all proposed rulemakings fourteen days prior to providing notice of the proposal to the public and the Secretary of State.[66]

In Case No. 92-131, the Department agreed that "it is appropriate to consider the potential for increased rates and resulting economic dislocation in developing and implementing its externality policy."[67] The Department, however, did not find support in the record for significant effects resulting from the Department's policy. The opinion notes a number of mitigating factors. First, the externality values are considered only in the selection of new resources and can only have a significant impact over a long period of time. Second, the evidence indicated that even under an aggressive resource procurement scenario rates would increase by only 5 percent by 2006 as a result of the consideration of externalities. Finally, the Department noted that much environmental regulation is national in scope and national environmental requirements may offset consideration of externalities by the Department. The Department concluded that:

[66] *Memorandum of Understanding Between the Department of Environmental Protection, the Department of Public Utilities, The Energy Facility Siting Council, and the Massachusetts Environmental Policy Act Unit of the Executive Office of Environmental Affairs, in regard to Department of Environmental Protection Review of Electric Generating Facilities* (July 10, 1990), 1-2; *Memorandum of Understanding on the Coordination of Regulatory Review by the Department of Public Utilities and the Department of Environmental Protection* (July 10, 1990), 1.

[67] *Investigation by the Department of Public Utilities On Its Own Motion As to the Environmental Externality Values to be Used in Resource Cost-Effectiveness Test by Electric*

> . . .[E]nvironmental externalities are real costs borne by ratepayers and the rest of society in the form of increased health care expenses, economic impacts on material and agricultural resources, and a reduced quality of life. Most important, we noted that increased short-term costs that may result from an environmental externality policy will be mitigated by long-term economic benefits in the form of lower costs to comply with increasingly stringent environmental regulations, and lower costs associated with the impacts of pollution upon society.[68]

New York

New York was among the first states to attach a monetary value to environmental externalities. It has continued a broad effort to improve the methodologies available for externality consideration.

In a 1989 case involving Orange & Rockland Utilities, the New York PSC reviewed proposed guidelines for the solicitation of capacity through competitive bidding procedures and developed monetary values which would be used in weighting alternative capacity proposals. In that case, there was substantial agreement among the parties that environmental impacts should be a factor in comparing different supply side technologies. The Commission found agreement that:

(..continued)
Companies Subject to the Department's Jurisdiction, Case No. 91-131, Opinion and Order (November 10, 1992), 14-15.

[68] Ibid., 15-16.

> . . .[A]lthough all projects proposed by bidders must meet environmental standards and must ultimately be evaluated and permitted to operate by appropriate regulatory agencies, meeting the threshold requirements will not make all projects environmentally equal. Because projects that are environmentally inferior (although approvable) might benefit from higher scores on their price bids, a fair bidding process should allow projects to receive higher scores based on environmental superiority. . .. Including environmental externalities in the bid ranking process recognizes that environmental impacts have economic value and that a project that reduces or avoids the level of pollution should be awarded a score that neutralizes the price advantage of a project that is less environmental benign. Recognition of environmental externalities in this fashion would increase efficiency in the allocation of resources and would anticipate the almost inevitable increasing cost of adverse environmental impacts in the future.[69]

Thus, the PSC decided that specific weight should be given to environmental mitigation in the scoring of supply side proposals. To establish this weight the Commission relied on judgmental estimates of mitigation costs supplied by the State Energy Office and developed for the State Energy Plan. Table 4-3 presents the values for external costs adopted by the New York PSC.

In the Orange and Rockland case, these estimates were then translated into a point total for scoring bids based on a comparison of mitigation costs to estimated levelized bid prices. In subsequent cases, the total of 1.405 cents per kWh (inflation adjusted) was applied to increase supply side costs when comparing the costs of demand- and supply side resources. It should be noted that land and water values generally have been considered to be similar for different types of supply side resources and thus have not provided a significant distinction between different supply side alternatives.

[69] *Re Orange and Rockland Utilities, Inc.*, Case No. 88-E-241, Opinion No. 89-7, 101 PUR 4th 280, 300 (April 13, 1989).

The New York PSC viewed these estimates as a starting point from which it would review methodologies which might be proposed by the utilities or other parties. The Commission has aggressively explored a broad range of issues associated with externality valuation and consideration of environmental factors. The PSC has initiated a five-track investigation into the consideration of Clean Air Act compliance costs and the incorporation of environmental externalities into the long-run avoided cost (LRAC)

TABLE 4-3 NEW YORK PSC EXTERNAL COST VALUATIONS	
Externality	**Mitigation Cost (¢/kWh)**
Air Emissions	
Sulfur Oxides	.25
Nitrogen Oxides	.55
Carbon Dioxide	.1
Particulates	.005
Water Impacts	.1
Land Use	.4
Total	**1.405**

Source: *Re Orange and Rockland Utilities, Inc.*, Case No. 88-E-241, Opinion No. 89-7, 101 PUR 4th 280, 300 (April 13, 1989).

estimates used in resource planning.[70] The LRAC plays a critical role in utility planning and the acquisition of demand-side and independent power resources in New

[70] *Proceeding on Motion of the Commission to Determine Whether to Incorporate Environmental Costs into the Long-run Avoided Costs for the State's Electric Utilities and Whether and in What Context Estimates of the Value of Externalities Should be Utilized*, Case No. 92-E-1187, Order Instituting Proceeding (December 29, 1992).

York. The Commission has requested comments from parties on issues related to the treatment of Clean Air Act compliance in LRAC calculations; how environmental externalities should be used in setting LRACs that are applied to supply side resources and DSM; how estimates of environmental externalities should be modified to reflect Clean Air Act compliance; whether and how estimates of externalities should reflect values for air toxics, CO_2, land use, water effluents, and thermal pollution; whether estimates of externalities should take into consideration socioeconomic effects related to job loss, fuel diversity, or rate impacts; determination of the appropriate values to use for externalities; determination of the impact of using emissions or total cost dispatch to estimate LRACs; and determination of the model to be used to incorporate externalities into LRAC estimates.[71]

As noted, the Commission directed the investigation of substantive issues to proceed in five partially parallel tracks:[72]

- Track 1: Clean Air Act Compliance. Utilities were required to file Compliance Plans associated with achieving phase I SO_2 emission reductions under Title IV of the 1990 Clean Air Act Amendments. The review of these plans was completed in June 1993. In May 1993, utilities were also required to file tentative compliance plans for phase II SO_2, Title I NO_x controls, and Title IV NO_x compliance.

[71] Ibid.

[72] *Proceeding on Motion of the Commission to Determine Whether to Incorporate Environmental Costs into the Long-run Avoided Costs for the State's Electric Utilities and Whether and in What Context Estimates of the Value of Externalities Should be Utilized*, Case No. 92-E-1187, Ruling on Procedural Schedule and Other Matters (April 22, 1993).

- Track 2: Policy Issues. This track involved the submission of policy positions and reply papers addressing issues raised in the questions posed in the Commission's Order initiating the investigation. A broad range of parties commented on the questions raised by the Commission and submitted reply comments. The matter is now before an administrative law judge with a decision expected in 1994.
- Track 3: Methodological Issues. This track would address such methodological issues as how externality estimates would be incorporated into LRACs for supply side resources, methods for internalizing externality valuations in

planning and dispatching, the externality valuations which should be used in evaluating specific demand-side resources, and the method for adjusting LRACs to take into consideration the cost of Clean Air Act compliance. Track 3 will proceed following the conclusion of Track 2, with technical sessions, the filing of direct and responsive testimony, and an evidentiary hearing. Track 3 is expected to build on the results of the Track 2 decision.

- Track 4: Valuation Issues. This track is designed to develop appropriate valuations for environmental externalities. It includes supervision of a collaborative study being undertaken in New York to develop damage cost assessments. The damage cost study is proceeding in three stages: (1) identification of all potential externalities, (2) screening and short-listing significant externalities for valuation, and (3) development of valuations for significant and quantifiable externalities and development of a computer model identifying the relationship between fuel use, emissions, dispersion of emissions, exposure of affected populations, dose-response relationships, and willingness to pay or other estimates of damage costs. The third stage of the study is currently expected to be completed in November 1994.
- Track 5: Examination of the Use of Total Cost Dispatch to Estimate LRACs. This track is examining the inclusion of externalities in utility unit commitment and dispatch and the use of full-cost dispatching in models used to estimate LRACs. Pursuant to a Commission Order, the New York Power Pool completed the first phase of a study on including specific externality adders in the dispatch process. The initial results of this study suggested that significant emission reductions could be achieved. However, the specific adders studied resulted in an increase in NO_x emissions in downstate New York, where there are severe ozone nonattainment problems. This issue might be addressed by the use of alternative externality adders or seasonal changes in dispatching to reflect that O_3 nonattainment occurs only during warm sunny months. The Commission staff has filed a motion to require the Power Pool to conduct additional analysis and to incorporate in its analysis likely Clean Air Act compliance strategies.

In the comments in the pending docket, there has been substantial discussion of competition, the impacts of the 1992 Energy Policy Act, retail wheeling, creating a level playing field between utility and nonutility power providers, and the potential for bypass because externality valuation might tend to put utilities in a noncompetitive position. The Commission requested comments on the average price impact of considering externalities. The PSC staff believes that rate impacts have been minimal given that the gas and DSM alternatives which have been winners under current procedures would also be cost-competitive without adders.[73]

Status of Commission Externality Consideration

These case studies, as well as decisions from other jurisdictions,[74] indicate that commission consideration of environmental externalities remains an incomplete and evolutionary process. To date, consideration of externalities has focused on the planning and/or acquisition of new generating capacity, unit life extensions, and DSM. A few states, such as Maine, Connecticut, and Massachusetts, have begun to recognize the potential of market-based systems of environmental regulation to achieve objectives that are both similar to and broader than that of commission externality considerations. Only limited attention, however, has been given to analyzing the best tools for internalizing environmental costs in utility resource planning and operations.

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[73] Nagebdra Subbskrishna, New York PSC Staff, Personal Communication with author, January 13, 1994.

[74] See, for example *In the Matter of the Report of the Externalities Task Force*, Docket No. U-0000-92-035, Decision No. 58237 (Arizona Corporation Commission, March 25, 1993); *Re Biennial Resource Plan Update*, 132 P.U.R. 4th 206 (CA PUC, April 22, 1992); *Re Integrated Resource Planning*, 139 P.U.R. 4th 379 (CO PUC, December 30, 1992); *Re Washington Water Power Co.*, 135 P.U.R. 4th 382 (ID PUC, July 16, 1992); *Re Comprehensive Energy Plan for the State of Illinois*, 132 P.U.R. 4th 49 (IL CC, March 31, 1992); *Re Rulemaking Regarding Resource Planning Changes Pursuant to S.B. 497*, 119 P.U.R. 4th 257 (NV PSC, January 22, 1991); *Re PacifiCorp*, 135 P.U.R. 4th 306 (Utah PSC, June 18, 1992).

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CHAPTER 5

RESOURCE ACQUISITION AND OPERATING STRATEGIES FOR ENVIRONMENTAL IMPROVEMENT

Planning and operating modern electric power systems involves several interlinked and complex tasks (Table 5-1). Accomplishing each so that consumers receive power reliably at an acceptable economic and environmental cost is difficult for several reasons. First, the electric system itself encompasses an interconnected array of a large number of electrical machines and circuits. Maintaining acceptable voltages and frequency in such systems under rapidly changing circumstances is by itself a daunting task. Second, scheduling short run generation and load management to minimize costs is complicated because of the sheer number of alternative schedules that are possible and by the uncertainties in load and equipment availability. Finally, long-term planning involves sorting through a wide range of possible resources and in-service dates, while keeping in mind the implications of each for short term schedules and costs.[1]

The various environmental policies discussed in earlier chapters--command-and-control regulations, emission caps, taxes, marketable permits, and emission adders--can impact all aspects of system planning and operation. In return, the decisions shown in Table 5-1 influence the type and degree of environmental impact caused by electricity generation, transmission, and use.[2] The purpose of this chapter is to explore the

[1] E. Hirst and C. Goldman, "Creating the Future: Integrated Resource Planning for Electric Utilities," *Annual Review of Energy* 16 (1991): 91-121.

[2] There are other decisions utilities can make that affect the environment. For instance, utilities can decrease environmental impacts by purchasing "offsets," such as New England Electric System's announced efforts to plant trees in Central America (see J.W. Rowe and C.A. LaFleur, "Environment, Economy, and Energy: Meeting the Multiple Challenges of the 1990s," *Electricity Journal* 5, no. 6 (1992): 42-49). Purchases of SO_2 emission allowances or NO_x emission offsets in non-attainment areas have similar effects. Utilities can also alter their environmental impacts via rate policies, such as considering external environmental costs in ratemaking policies (C.K. Woo, B.F. Hobbs, R. Orans, R. Pupp, and B. Horii, "Emission Costs, Customer Bypass, and Ramsey Pricing of Electricity," Submitted to *Resource and Energy Economics*, April 1994.) Although rate reform or offsets will often have a lower cost than other emission reduction strategies, for purposes of this discussion the focus is on how utilities can lower their emissions more directly via resource acquisition and system operation.

TABLE 5-1

OVERVIEW OF UTILITY PLANNING AND OPERATIONS PROBLEMS

RESOURCE AND EQUIPMENT PLANNING

RESOURCE PLANNING AND PROCUREMENT (ten to forty year horizon) [illegible] (three to fifteen years) Given [illegible] should be considered.
TRANSMISSION AND DISTRIBUTION PLANNING (five to fifteen years) Given load forecasts and planned generation additions, design circuit additions that maintain reliability, minimize costs, and avoid possible environmental effects such as aesthetic impacts or exposure to EMF.

MEDIUM TERM OPERATIONS PLANNING

FUEL SCHEDULING (one year) Within limitations of long-term fuel contracts, schedule fuel deliveries and storage to meet plant requirements.
MAINTENANCE AND PRODUCTION SCHEDULING (two to five years) Given load forecasts and available equipment, schedule [illegible] maintenance to maintain reliability and minimize costs. Schedules can account for seasonal differences in emission restrictions, if any.

SHORT RUN OPERATION

DISPATCH / AUTOMATIC PROTECTION (fractions of a second) / UNIT COMMITMENT (eight hours to one week) [illegible]
[illegible] ... costs must be considered. Unit commitment can be altered to decrease overall system emissions (usually air pollutants), or just those at certain times or from certain facilities.

Source: Adapted from S.N. Talukdar and F.F. Wu, "Computer-Aided Dispatch for Electric Power Systems," *Proceedings of the IEEE* 69, no. 10 (October 1981).

relationships between utility choices and impacts, as they are affected by the particular environmental policies adopted.

In this chapter and the next, it is explained how resource and equipment planning, operations planning, and real time operations each affect utility costs and emissions. This is done using as an example a simple generation system that has two "products": electricity and CO_2. This chapter shows how different planning and operating decisions result in different combinations of generation cost and emissions. Then in Chapter 6, how various policies can affect a utility's choice from among those options is explored. Some policies will yield inefficient outcomes, that is, plans and operating strategies for which there exist alternatives that would result in both lower emissions and costs. Other policies are more likely to motivate the utility to choose efficient mixes. Policies that appear to be very different, such as emission allowances, taxes, and total emission caps, can yield similar--and efficient--

outcomes. Finally, also in Chapter 6, some actual examples are explored of how operating strategies can be used to achieve cost-effective environmental improvement.

Multiobjective Framework for Evaluating Resource Options and Operating Strategies

Multiobjective plots, such as Figure 5-1, are a useful tool for understanding how coherent environmental compliance plans can be assembled. This device is used to illustrate how long- and short-run strategies complement each other; both are needed in order to ensure an efficient outcome. Multiobjective plots can show how the options available to the utility affect important objectives, such as costs, rates, emissions, resource use, and financial indices. Figure 5-1 is a two-dimensional plot in which the only objectives are incremental generation cost (the y-axis) and CO_2 emissions (the x-axis). In general, each point can be a distinct plan representing a particular combination of supply sources, environmental controls, demand-side management programs, and rate design, along with a unique operating strategy.[3]

[3] To be more precise, the cost axis represents all variable costs of generation, plus any annualized costs of new generation plants and DSM programs. It is assumed here that the costs and emissions resulting from a particular plan can be predicted with certainty. In reality, uncertain fuel prices, loads, and other factors mean that the location of each point should be described by a probability distribution or confidence interval. The points shown could also represent an average for each plan across a set of scenarios (C.J. Andrews and S.R. Conners, "Existing Capacity: The Key to Reducing Emissions," *Energy Systems and Policy* 15, no.3 (1991): 211-30).

Fig. 5-1. Tradeoff plot: CO_2 versus cost for seven plans (Source: Authors' construct).

The concepts are illustrated by examining the options facing a hypothetical small utility. The utility's peak load in the year 2010 is projected to be 1,050 MW. Its present generation mix consists of three coal units (500 MW total), an oil-fired steam unit (150 MW), and natural gas-fire combustion turbines (200 MW). The options available for meeting loads and decreasing emissions by a combination of emissions dispatch (operating cleaner plants more and dirtier plants less), fuel switching (in particular, cofiring natural gas at the second coal unit), acquiring supplies (new pulverized coal plants, gas-fired combined cycle, or combustion turbine capacity), and investing in energy efficiency (DSM-EE) and load controls (DSM-LC). Figure 5-1 shows the resource additions made in each of several plans, assuming that generation is dispatched in order to minimize utility costs.[4] Appendices A and B document the linear program used to evaluate alternative plans and the assumptions made in the case study.

Some plans in Figure 5-1 yield both high internal costs and high emissions (for example, Plan G). These plans are obviously inferior to other plans which have both lower costs and emissions (such as Plan A). Plans that are not superseded by any other plans are (for purposes of this discussion) the "efficient" alternatives (here, Plans A, B, C, and D, which are connected by a dotted line). Alternatives to a particular efficient plan have either higher costs or higher emissions. If all a planner cares about is revenue requirements and CO_2, then only efficient plans are of interest.[5] This curve can be used to calculate the marginal cost of achieving each increment of reduction. For instance, moving from Plan B to Plan C involves a reduction of 150,000 tons of CO_2 at a cost of $1.5 million, implying a marginal cost of $10 per ton of emissions decrease. Improved technology would shift the curve in toward the origin, lowering emissions, costs, or both.

Some researchers argue that the purpose of modelling should be to screen and define the efficient set and eliminate inferior alternatives.[6] It is then up to policymakers to make the

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[4] The relatively small numbers for generation capacity additions result from the assumption that fractions of units can be acquired through joint ownership of facilities with other utilities.

[5] J. Cohon, *Multiobjective Programming and Planning* (New York: Academic Press, 1978); W.J. Burke et al., "Trade Off Methods in System Planning," *IEEE Transactions on Power Systems* 3, no. 3 (1988): 1284-90.

[6] Ibid.

value judgments necessary to choose from among the surviving options. This information supports negotiations by helping participants focus on the key issues and available tradeoffs.[7]

[7] C.J. Andrews, "The Marginality of Regulatory Marginal Investments: Why We Need a Systemic Perspective on Environmental Externality Adders," *Energy Policy* (May 1992): 450.

Environmental planning can be viewed as the process by which the utility chooses from the possibilities in Figure 5-1. The government sets some rules as to which points are admissible and how the utility should weigh the tradeoffs between the two objectives of minimizing internal costs and minimizing emissions. These rules may give the utility little discretion, or they might allow considerable flexibility. Later in this chapter, it is shown how different rules affect the utility's choices. However, first three categories of options which together determine the utility's costs and emissions are discussed: short-run operations, medium-term operations planning, and long-run resource planning. It is then shown how they can be integrated. In addition, there is a discussion on how price-elastic energy demands can alter the outcomes of emissions-cost tradeoff analyses.

Short-Run Operations

Unit commitment and dispatch can drastically affect both system costs and emissions. The difference between unit commitment and dispatch is that the commitment problem involves the determination of which units should be on line and available to take load at which times, whereas dispatch concerns how much power each on-line unit should produce on a minute by minute basis. For the purposes of this discussion, the term "dispatch" broadly encompasses both commitment and real-time dispatch.

Traditionally, utilities have operated their generation systems to minimize fuel and other variable costs, subject to reliability restrictions. This generally results in "least-cost" dispatch, in which units with the lowest variable cost are used first and more expensive units are dispatched only when loads exceed the capacity of the cheaper units. The "merit order"--the order in which generating units are dispatched--is constructed by ranking the units in order of cost.[8]

[8] Complications caused by transmission limits and losses and nonconstant variable costs are ignored here. See A.J. Wood and B.F. Wollenberg, *Power Generation Operation and Control* (New York: Wiley, 1984).

However, if a utility also is concerned with environmental impacts, it might alter the merit order in order to decrease its emissions. This is called emissions dispatch: the operation of a generation system so that generating units that have higher emission rates (on a pound per kWh basis) produce less power and, thus, fewer emissions than they would if dispatched on a strict least-cost basis. Consequently, cleaner units generate more power, system emissions are reduced, and increase utility costs compared to least-cost dispatch. As case studies discussed in this chapter show, the result can be significant emission reductions whose costs are well below those of other emission-control options.

Emissions dispatch is not used here to mean "least-emissions dispatch," in which the sole objective is to minimize the amount of emissions. Rather, it is a composition of least-emissions and least-cost dispatching.[9] As an example, consider a system with just three generating units, each 100 megawatts (MW) in size, and imagine that SO_2 is the pollutant of concern. Unit 1 is a natural-gas fired facility with no SO_2 emissions and a marginal cost of \$30 per MWh. Unit 2 burns low-sulfur coal, has an emissions rate of thirty pounds of SO_2 per MWh, and a marginal cost of \$24 per MWh. Finally, Unit 3 burns high-sulfur coal, emits forty-eight pounds per MWh, and costs \$15 per MWh to run. Assume that there are no planned or forced outages, and no operating restrictions such as minimum run levels.

Let us assume that these plants are dispatched to meet a load of 150 MW. Least-cost dispatching would mean that Unit 3 would bear 100 MW of the load, and Unit 2 would shoulder the rest. The resulting cost is \$2,700 per hour or 100 MW X \$15 per MWh + 50 MW X \$24 per MWh. Emissions would be estimated by a similar calculation, and would equal 6,300 pounds per hour. In contrast, least-emissions dispatch would run Unit 1 at 100 MW and Unit 2 at 50 MW. The total cost would increase by more than 50 percent to \$4,200 per hour, and emissions would fall to 1,500 pounds per hour. The cost of reducing emissions by moving from least-cost dispatching to least-emissions dispatching can be calculated as

[9] S. Bernow, B. Biewald, and D. Marron, "Full-Cost Dispatch: Incorporating External Costs in Power System Operations," *The Electricity Journal* (March 1991): 20-33.

(\$4,200 - \$2,700)/(6,300 pounds - 1500 pounds), or \$625 per ton of SO_2. Compared to other options, this may be an expensive means of lowering emissions.

However, consider the following intermediate emissions-dispatching order. Let Unit 3 produce 100 MW, as in least-cost dispatching, but use gas-fired Unit 1 rather than coal-fired Unit 2 to meet the remaining 50 MW. The total cost would then be \$3,000 per hour, and the emissions 4,800 pounds per hour. Compared to least-cost dispatching, a reduction of 1,500 pounds per hour has been achieved at a cost of \$300 per hour. This is an incremental expense of \$400 per ton, which may be cost-effective compared to other SO_2 reduction options.

The simplest way to generate alternative merit orders is to add a hypothetical tax or penalty to the variable cost of each generating unit equal to an assumed cost per pound of emissions times that unit's emission rate.[10] Then a merit order can be created based on this composite cost objective, and the resulting emissions and out-of-pocket costs estimated. For instance, a tax of \$500 per ton would have yielded the following merit order in the above example: Unit 3 first, then Unit 1, and last Unit 2.[11]

Figure 5-2 illustrates this concept for the generation system of Appendix A. A fixed generating mix is assumed, based on Plan A of Figure 5-1 in which no additional DSM is acquired and 145 MW of combined cycle and 212 MW of combustion turbine capacity is purchased or built. This is the plan that minimizes total cost without regard

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[10] For example, see J.K. Delson, "Controlled Emission Dispatch," *IEEE Transactions on Power Apparatus and Systems*, PAS-93(5) (Sept./Oct. 1974): 1359-1366; J.S. Heslin and B.F. Hobbs, "A Probabilistic Production Costing Analysis of SO_2 Emissions Reduction Strategies for Ohio: Emissions, Cost, and Employment Tradeoffs," *Journal of the Air and Waste Management Association* 41, no. 7 (1991): 956-66.

[11] Emissions dispatch schemes can also be used with a constraint on total emissions, constraints on individual emission rates, and constraints or taxes on pollutant concentrations rather than emissions (R. Petrovic and B. Kralj, "Economic and Environmental Power Dispatch," *European Journal of Operational Research* 64, no. 1 (1993): 2-11; J.H. Talaq, F. El-Hawary, and M.E. El-Hawary, "A Summary of Environmental/Economic Dispatch Algorithms," *IEEE Transactions on Power Systems* (forthcoming).

Fig. 5-2. Effect of emissions dispatch upon emissions and cost under plan A (Source: Authors' construct).

to emissions. Strict least-cost dispatch of this system results in the point on the lower right (marked "$0 per ton"). Coal plants are baseloaded, the oil-fired and combined cycle facilities serve intermediate loads, and combustion turbines meet peak loads. The merit orders and capacity factors of the facilities under this dispatch order are shown in the first column of numbers in Table 5-2.

If instead a hypothetical tax of $10 per ton is applied to CO_2 emissions, then the merit order shifts, as the second column of numbers in Table 5-2 indicates. Under a zero CO_2 tax, Coal 1 was dispatched after Coal 3, because Coal 1 is scrubbed and has a

TABLE 5-2

MERIT ORDER (CAPACITY FACTOR) OF GENERATING PLANTS
UNDER DIFFERENT DISPATCH STRATEGIES

Generating Unit	CO_2 Tax, $/ton				
	0	10	15	20	30
Coal 1 (Scrubbed, High Efficiency)	3(0.72)	2(0.85)	2(0.85)	4(0.59)	4(0.59)
Coal 2 (Unscrubbed, High Efficiency)	1(0.85)	1(0.85)	1(0.85)	1(0.85)	2(0.77)
Coal 3 (Low Efficiency)	2(0.82)	3(0.64)	4(0.38)	5(0.29)	5(0.29)
Oil Steam	4(0.39)	4(0.39)	3(0.65)	3(0.57)	3(0.63)
New Combined Cycle	5(0.29)	5(0.29)	4(0.29)	2(0.83)	1(0.85)
Combustion Turbines	6(0.08)	6(0.08)	6(0.08)	6(0.08)	6(0.08)
Total CO_2 Emissions (Million tons/year)	4.88	4.85	4.71	4.28	4.24

Source: Authors' construct.

Note: Capacity Factor = Annual MWh Output/(MW Capacity * 8760 Hours)

a higher nonfuel variable cost. But under a $10 tax, Coal 1 carries more load, and Coal 3 carries less; this is because Coal 1 has a lower heat rate, and thus lower CO_2 emissions per kWh. The result is the decrease in emissions and rise in cost indicated in Figure 5-2. The cost axis in Figure 5-2 indicates *only* the out-of-pocket cost of the utility; the hypothetical CO_2 tax is excluded.

Higher taxes shift the merit order around even more; at $15 per ton, the oil steam plant is dispatched ahead of Coal 3 (Table 5-2), resulting in more substantial emission reductions. At $20 per ton, the oil and combined cycle facilities are dispatched ahead of all the coal plants except the very efficient Coal 2. At $30 per ton, the combined cycle facility is baseloaded, and the coal plants are cycled to the extent that their minimum run restrictions allow. Figure 5-2 shows that as a result of this, CO_2 emissions can be decreased by up to 15 percent at a net cost of $10 million per year.[12]

The points are connected by line segments because it is possible to continuously vary the dispatch of the system between the points shown. However, that is not always true, as some of the emissions reductions may be achieved by discontinuously reducing the output of some dirtier units from their minimum run levels to zero. To consider this complication, environmental unit commitment models are necessary, some of which are becoming available.[13]

[12] These emission reductions are less than might be inferred from Bernow, Biewald, and Marron's ("Full-Cost Dispatch: Incorporating External Costs in Power System Operations," 20-33) hypothetical analysis because we have explicitly included minimum run requirements that prevent full cycling of coal facilities. Careful analyses of New England (J.F. Busch and F.L. Krause, "Environmental Externality Surcharges in Power System Planning: A Case Study of New England," *IEEE Transactions on Power Systems* 8, no. 3 (August 1993): 789-95), Ohio (J.S. Heslin and B.F. Hobbs, "A Probabilistic Production Costing Analysis of SO_2 Emissions Reduction Strategies for Ohio," 956-66), and other regions have explicitly imposed operating restrictions using sophisticated production costing models; they give a more realistic picture of the emission reductions that are possible.

[13] C. Marnay, "Intermittent Electrical Dispatch Penalties for Air Quality Improvement," Ph.D. Dissertation, Berkeley, California, University of California, 1993; T. Gjengedal, O. Hansen, and S. Johansen, "Qualitative Approach to Economic-Environmental Dispatch; Treatment of Multiple Pollutants," *IEEE Transactions on Energy Conversion*, 7, no. 3 (September 1992): 367-373; S. Kuloor, G.S. Hope, and O.P. Malik, "Environmentally Constrained Unit Commitment," *IEEE Proceedings-C* 139, no. 2 (March 1992): 122-28.

Tradeoffs between internal cost, CO_2 and other objectives, such as minimizing NO_x or maximizing employment in local coal fields, can be easily generated by a generalization of this tax procedure. First, each objective would be mathematically defined as a linear function of the energy produced by each generation types. Merit orders would then be created based upon a weighted sum of all the objectives, with the generation unit with the lowest value per MW being dispatched first. Finally, the weights would be varied systematically, each set of weights yielding a different distribution of output among the units. The resulting changes in the values of the various objectives for the system as a whole are then plotted.[14]

The curve in Figure 5-2 can be viewed as a short-run total cost curve for emissions reductions, as it holds capital investments fixed. Long-run curves, which reflect possible investments in resources and control technologies, are the subject of the next two subsections.

Medium-Term Operations Planning

The next level of complexity in an environmental planning exercise would be to go beyond an analysis of dispatch to consider possible medium-term fuel changes and perhaps emission-control retrofits, and their interactions with emissions dispatch. Medium-term strategies usually involve lump-sum expenditures of capital and changes in the efficiency, capacity, emission and outage rates of generating units. For example, switching to low-sulfur coal will mean that fuel and handling equipment may have to be altered because of changes in the coal's ash content or grindability. However, these investments are usually relatively small compared to the cost of acquiring new resources.

[14] Heslin and Hobbs, "A Probabilistic Production Costing Analysis of SO_2 Emissions Reduction Strategies for Ohio;" Ibid., Gjengedal, Hansen, and Johansen, "Qualitative Approach to Economic-Environmental Dispatch."

It is important to consider these types of investments using a model of the entire generation system. Simple analyses which study possible investments in isolation from each other may miss important interactions with other investments and dispatch strategies. For instance, changes in the generating unit's variable cost and emission rate may alter the dispatch order, perhaps shifting system costs and emissions in surprising ways. Moreover, stack gas controls generally lead to capacity deratings and higher outage rates, implying that power will have to made up from other generating units.

As an illustration, the possibility of retrofitting Coal 2 in the hypothetical system with the capability to cofire up to 15 percent natural gas is considered. This will increase that unit's variable cost because of the expense of gas, but lower its CO_2 emissions from 1.15 tons per MWh to 1.08 tons per MWh. As Table B-2 in Appendix B shows, the cost of retrofitting the boiler with gas burners is assumed to be $9 per kW of capacity. Cofiring also lowers nonfuel variable costs because of avoided ash handling expenses. Possible changes in the unit's heat rate and maximum and minimum MW outputs are ignored.[15]

Whether such a medium-term option is cost-effective can be assessed by the hypothetical tax method used above for emissions dispatch. If cofiring natural gas results in a lower value of the composite (with tax) cost function compared to not cofiring, then it is judged cost-effective at the assumed tax. Of course, the annualized cost of the cofiring investment is included in the calculation of utility cost.[16] The results are shown in Figure 5-3, where the emissions-dispatch-only curve of Figure 5-2 is superimposed on a curve which

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[15] See B.F. Hobbs et al., "What's Flexibility Worth? The Enticing Case of Natural Gas Cofiring," *The Electricity Journal* 5, no. 2 (March 1992): 37-47, for a more careful analysis of cofiring's potential, and its interaction with emissions dispatch.

[16] The cost-effectiveness test is applied by using Appendix A's linear programming model to choose the optimal fuel mix and dispatch order, given the fixed assumed values of generation capacity and DSM programs. Note that this analysis is for one year using annualized capital costs. A more complete present worth analysis over a time horizon of twenty years or more might yield different conclusions about the relative attractiveness of the medium-term strategy.

also includes the option of cofiring. In the cofiring curve, cofiring only takes place if it lowers total cost (including CO_2 penalties). At taxes of $0 through $15, installing cofiring is not worthwhile, and the points of the two curves are almost coincident, as shown. The difference between the two curves results from the (small) cost of installing the capability to cofire gas.

But if the tax is increased to $20 per ton or more, then gas is cofired at Coal 1 because, at that tax, the additional cost of natural gas is more than offset by the value of the emissions decrease. The result is lower emissions but higher costs compared to the dispatch-only curve. For instance, comparing the two $30 points, cofiring would drop emissions by 65,000 tons per year while raising costs by $1.2 million.

Fig. 5-3. Comparison of plan A with and without option of cofiring under emissions dispatch (Source: Authors' construct).

Resource Acquisition Decisions

Several categories of long-run alternatives are available to our hypothetical utility: life extension, strategic conservation, and new fossil-fueled power plants. Utilities have other options too, such as purchasing or sales of bulk power, other types of DSM programs, and renewable energy sources. The number of possible combinations of resources that satisfy reserve margin requirements can be very large. Figure 5-1, above, plots just a handful of combinations; actual studies generally show many more.[17] In each of the plans shown in Figure 5-1, least-cost dispatch is assumed.

Figure 5-1, however, would be a poor way to judge the merits of the various plans. This is because the most cost-effective emissions strategy is likely to be a combination of emissions dispatch, fuel switching, and acquisition of cleaner resources. Figure 5-1 does not consider the interaction of different resource mixes with operational strategies; it is likely that some resource mixes will provide more opportunities for emissions dispatch and fuel switching than others.

Figure 5-4 corrects this oversight by plotting the performance of combinations of strategies. Each curve results from one capacity mix, and represents the emissions and costs resulting from different degrees of emissions dispatch and cofiring, where available. The right-most points on each curve are the least-cost dispatch solutions shown in Figure 5-1. The left-most points correspond to a CO_2 tax of $30 per ton. As asserted in the previous paragraph, some plans do indeed have much more potential for emissions dispatch than others: for instance, compare Plan G (New Coal) with Plans A, B, C, and D, each of which involve some combined-cycle capacity (see Figure 5-1). The latter plans have a mix of gas and coal-fired capacity that offers more opportunity for lowering emissions by altering dispatch order.

Although some of the least-cost dispatch points appeared to be efficient in Figure 5-1, most of them are inferior to strategies that involve some emissions dispatch in Figure 5-4. Consider, for example, the right-most point of Plan D's curve. This is the least-cost dispatch of a system in which 80 MW of DSM was acquired along with 265 MW of combined cycle capacity, and cofiring capability has been installed in Coal 2. This point is now inferior to

[17] For example, see Clinton J. Andrews, "The Marginality of Regulating Marginal Investments; E.O. Crousillat, P. Dorfner, P. Alvarado, and H.M. Measill, "Conflicting Objectives and Risk in Power Systems Planning," *IEEE Transactions on Power Systems* 8, no. 3 (August 1993): 887-93.

both the second and third points from the right on Plan C's curve. The third point represents dispatch at $15 per ton of a system in which

Fig. 5-4. Identification of efficient combinations of resource and operating strategies (Source: Authors' construct).

80 MW of DSM has been added, along with 151 MW of combined cycle units, and 115 MW of combustion turbines. Although Plan C's combustion turbines have a higher emission rate than the 115 MW of Plan D's combined cycle capacity they replace, C's capital cost savings plus some emissions dispatch yield both lower costs and emissions than Plan D's least-cost dispatch point.

Efficient strategies in Figure 5-4 are connected by a dotted line; no other strategies simultaneously have lower emissions and costs. The best plans under eight different values of the CO_2 tax are indicated as P_x, where x is the tax.[18] With the exception of the least-cost point P_0, *all* of the efficient strategies involve at least some emissions dispatch. This is a general rule: efficient emissions control involves both short- and long-run strategies. It can be shown that both short- and long-run measures should be adopted until the marginal cost of additional measures of each type equals or exceeds the assumed tax.

Effects of Rates on Loads, Costs, and Emissions

Calculations of the emissions and costs of the strategies displayed in Figures 5-1 through 5-4 all assume that differences in electric loads among the strategies result only from differences in DSM programs. Electric rate changes caused by differences in costs are assumed to have no effect on loads.

Of course, this is not the case. The quantity of electricity demanded is a function of the price. Rate increases would be necessary to cover the extra $22 million per year that Plan P_{30} costs compared to P_0 (Figure 5-4); as a result, loads will decrease, and so will generation costs and emissions. If rates exceed the marginal cost of generating power, then rate increases will be even greater because of the lost revenues resulting from additional DSM programs.

As an exampleof this phenomenon of rate feedback, let us assume that the load is consistent with the costs incurred by Plan P_0, and the resulting retail rate would be 6 cents per kWh. Further, assume that the price elasticity of demand is 0.6, and that rate increases would cause loads to decrease by an equal proportion in all periods. It can be shown that if the resource mix and system operation is optimized using a tax of $30 per ton, then rates would increase 10.2 percent, and loads would fall by 6.1 percent.[19] The result is shown in Figure 5-5, where Plans P_0 through P_{30} are contrasted with a Plan P_{30},

[18] Efficient strategies can be found more directly by optimizing the full linear program of Appendix A, including new capacity variables, under various assumed taxes.

[19] This is accomplished by using the cob-web algorithm: the full linear programming model of Appendix A is solved under a $30 penalty and an assumed energy demand. Then the resulting costs are used to adjust the average cost-based price. A new energy demand is then calculated and is returned to the LP, which is solved again, and so on.

Fig. 5-5. Effect of rate feedback upon emissions and costs of plan P (Source: Authors' construct).

which is modified to account for rate feedback. Rate feedback lowers costs by $17 million per year compared to the no feedback case, and emissions fall by 61,000 tons per year.

Rate feedback seemingly bestows a free lunch: costs *and* emissions decrease compared to the original P_{30}. If the modified P_{30} is compared to P_0 (the base case), the apparent cost per ton of CO_2 reduction is a mere $4 per ton; by comparison, the per ton cost of moving from P_0 to P_{30} is $22 per ton. If this rate feedback is calculated for all other options, then points P_5 through P_{25} would also shift down and to the left. This forms a new curve connecting P_0 with modified P_{30}, where the cost per ton of reduction for all options P_5

through P_{30} would be lower than when rate feedback is not considered. This points out that rate feedback--which is too often ignored--can drastically alter the conclusions of a cost versus emissions analysis.

However, this free lunch is illusory, because there is an important category of societal cost that is not included in the figures. By raising rates, electric customers will be discouraged from buying electricity that would otherwise provide value. This foregone value is a real economic cost of the rate increase. Quantification of this lost customer value could change the outcome of a benefit-cost analysis of emissions reductions.[20,21] The general issue of social welfare gain or loss versus the cost will be revisited in Chapter 7 in the context of overall environmental regulation.

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[20] As an example, B.F. Hobbs and J.S. Heslin, "Evaluation of Conservation for SO_2 Emissions Reduction Using a Multiobjective Electric Power Production Costing Model," in *ACEEE 1990 Summer Study on Energy Efficiency in Buildings* (Washington D.C.: American Council for an Energy Efficient Economy, 1990), 4.65-4.77, use the concept of consumers' surplus to quantify this lost value for a SO_2-cost tradeoff curve for Ohio. They set lost value equal to the price of electricity times the rate-induced decrease in energy demanded. See K.W. Costello and P.S. Galen, *A Proposed Methodology for Evaluating Utility Conservation Programs*, Docket Nos. 83-0034 to 83-0043, Illinois Commerce Commission, Springfield, Illinois, 1983; or S.D. Braithwait and D.W. Caves, "Three Biases in Cost-Efficiency Tests of Utility Energy Efficiency Programs," *The Energy Journal* 15, no. 1 (January 1994): 95-120, for discussions of the use of consumer surplus in evaluating resource plans.

[21] Another impact of higher electricity prices is that electricity end users may substitute other fuels for electricity; in theory, the net environmental effects of resource choices might then be considerably different than just the changes in the utility's emissions. It has been argued that because of such substitution effects, the result of including externalities in utility planning might actually be to worsen rather than improve the net impact of energy use on the environment (L. Ruff, *Internalizing Environmental Costs in Electric Utility Decisions*, Unpublished manuscript, May 1991).

An investigation into this question was conducted for Seattle City Light (SCL), a northwestern U.S. utility (B.F. Hobbs, "Emission-Cost Tradeoffs for Electric Utilities: The Effect of Rate Feedback," *Journal of Energy Engineering* (in review). The rate increases necessary to pay for a large decrease in SCL's CO_2 emissions would induce significant increases in residential consumption of fuel oil, natural gas, and wood. However, the resulting increases in CO_2, NO_x, and particulate emissions are unimportant compared to the direct change in SCL's emissions and can be disregarded.

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CHAPTER 6

ENVIRONMENTAL POLICIES AND UTILITY DECISIONS

Government laws and regulations limit those points in Figure 5-4 which can be considered by the utility, as well as the method used by the utility to weigh the tradeoffs among the cost and environmental objectives. In this chapter, how alternative government environmental policies affect utility planning is discussed. The policies considered include traditional command-and-control regulations, constrained emissions, internalization of environmental costs via taxes or marketable emission credits, and internalization of environmental costs via planning regulations.

The policies are compared in terms of whether they motivate the utility to choose an efficient plan and whether that plan also minimizes total social cost. "Social" cost is defined for purposes of this discussion, as the sum of utility costs plus emissions of each type times the appropriate damage cost per ton for each type. As a hypothetical case, if damages are $10 per ton for CO_2, then the least social cost plan in Figure 5-4 is Plan P_{10}, which is the point at which the marginal internal cost of reducing emissions further by moving to Plan P_{15} exceeds $10 per ton.[1]

Command-and-Control Regulations

Examples of command-and-control regulation include local restrictions on fuel sulfur content, federal New Source Performance Standards, and Best Available Control Technology rules. The effect of policies of this type is to render some of the points in Figure 5-4 illegal.[2] Only those plans that conform to the regulations can be considered.

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[1] This assumes that changes in the price of electricity do not induce consumers to alter the amount of power they consume.

[2] Of course, there are no CO_2 regulations at the present time; their existence is assumed in this section merely to make a point about the theoretical inefficiency of the command-and-control approach.

The utility is then free to choose from the permissible plans in order to minimize its internal cost. The emissions of those plans are ignored.

For instance, say that a policy is adopted that prohibits new coal plants or new fossil-fuel plants with heat rates higher than 9,000 Btus per kWh. For our hypothetical utility, this results in elimination of all alternatives involving new combustion turbines and coal plants, and leaves only strategies represented by the solid line in Figure 6-1. The utility will choose Plan $P_{C\&C}$, which is the cheapest plan that excludes new plants of that type.

Fig. 6-1. Inefficiency of a ban on new coal and combustion turbine facilities (Source: Authors' construct).

By focusing on individual supply resources, fuels, and emission controls, the command-and-control approach ignores the environmental benefits of DSM and emissions dispatch. As a result, superior solutions that have lower costs and emissions may be prematurely eliminated. For instance, Plan P_{10} in Figure 6-1 represents a combination of DSM programs and emissions dispatch together with some combustion turbine additions. The new turbines lower the system's cost but also makes the plan illegal. The utility could compensate for the higher emissions rate of the turbines through dispatch and DSM, but command-and-control regulations do not permit consideration of that strategy. The result is that the utility will choose $P_{C\&C}$ instead, which unfortunately gives both higher costs *and* more emissions than point P_{10}.

An unfortunate consequence of command-and-control regulation is that even if the environmental damages of CO_2 are high, the utility has no incentive to use dispatch and DSM to reduce emissions beyond the legal requirements. This is true even if the cost of doing so is small compared to those damages. Thus, the utility's choice under command-and-control regulation is unlikely to minimize total social cost.

Constrained Emissions

Another philosophy of environmental regulation, called "environmental least-cost utility planning" (ELCUP), instead specifies the problem as follows.[3] The utility is to minimize its internal cost, subject to a constraint on overall emissions. For instance, Figure 6-2 shows the effect of imposing a cap of 4.4 million tons per year of CO_2, 10 percent below the least-cost level. It would motivate the utility to choose point P_{15}, as all the lower-cost points to the right of the constraint are rendered infeasible by the cap.

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[3] S. Brick and G. Edgar, "Blunting Risk With Caution: The Next Step for Least-Cost Planning," *The Electricity Journal* (July 1990).

ELCUP is law in only one jurisdiction, Wisconsin, which constrains overall utility NO_x and SO_2 emissions (see Chapter 4). However, several utilities, including Niagara Mohawk, New England Electric System, and Southern California Edison voluntarily

Fig. 6-2. Environmental least-cost planning: imposition of a CO_2 cap (Source: Authors' construct).

adopted this approach for the case of CO_2 emissions. This approach has been encouraged under President Clinton's greenhouse warming policy. Also, some utilities complying with the Clean Air Act's acid rain provision may naively view the number of SO_2 allowances they were granted as a fixed constraint; however, most could further lower their compliance costs by either selling or buying allowances.

The advantage of ELCUP over the command-and-control approach is that the utility can freely choose from any combination of supply resources, emission controls, DSM programs, and dispatch strategies in order to meet the constraint. Unlike command-and-control regulations, an efficient point will always result from this process, at least in theory.

If the marginal external cost of emissions happens to be the same as the marginal internal cost of emissions reduction at point P_{15}, then ELCUP also results in the least social cost plan. However, in general, ELCUP may result in too much or too little emissions reduction, especially if the damages of pollution are poorly understood or if the marginal expense of pollution control was not considered in setting the constraint.[4]

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[4] A variation of the ELCUP approach is to constrain the average emissions *rate*, measured in terms of pounds per kWh or pounds per mmBtu of heat input. The use of a rate rather than total emissions can result in inefficient solutions (that is, higher costs and emissions than necessary) and operating difficulties. For instance, the California South Coast Air Quality Management district limits average NO_x production by Southern California Edison's units in the Los Angeles basin using a pounds-per-MWh standard (S.W. Hess et al., "Planning System Operations to Meet NO_x Constraints," *IEEE Computer Applications in Power* 5, no. 3 (July 1992)). This causes problems during days with low loads, as NO_x emission rates (on a pounds-per-MWh basis) increase when generating units are lightly loaded, even though total emissions (in pounds) are lower. This rule also gives no incentive to invest in DSM or shift generation to less sensitive areas outside the basin.

Taxes and Emission Allowances

External environmental costs can be internalized by imposing emission taxes or by creating marketable emission credits. The effect of taxes and marketable credits is to make emissions an internal cost from the utility's perspective. For instance, assume that a CO_2 tax of $15 per ton is levied or, alternatively, that the utility must secure emission allowances whose market price is $15 per ton. The hypothetical utility will minimize its costs by minimizing the sum of its capital, fuel, and variable costs (COST, the vertical axis of the figures) plus $15 X CO_2, where CO_2 is its emissions (the horizontal axis). This process is shown in Figure 6-3 in which isoquants of the quantity COST + $15 X CO_2 are shown. The point lying on the lowest such isoquant is the plan that minimizes the utility's total cost. In Figure 6-3, this is point P_{15}. Like the ELCUP approach

Fig. 6-3. Effect of CO_2 tax of $15 per ton upon plan choice (Source: Authors' construct).

but unlike command-and-control regulations, the resulting point is in theory efficient because the benefits of *all* options for reducing emissions, including DSM and dispatch, are recognized.

In the case of marketable emission allowances, this result assumes that the utility is free to buy and sell emission allowances. Even if the utility is initially granted sufficient credits, as some utilities are for SO_2 under the 1990 Clean Air Act's acid rain program, it should still value them using the market price because an emission credit consumed is one that cannot be sold. However, in practice some restrictions, such as a political constraint,[5] might prevent achievement of an efficient solution. For example, under the acid rain program, some states are considering a prohibition on utilities from selling allowances to upwind utilities or from abandoning use of local high-sulfur coal. Possible rationales for such restrictions are that the allowances ignore the fact that the location of emissions affects the environmental damage they cause and that there are social objectives in addition to internal cost and emissions.

Emission taxes will motivate the utility to choose the least social-cost point if the tax rate equals the marginal damage cost of emissions, as discussed in Chapter 2. Then the utility's total cost and society's cost are identical. The case of emission allowances is more complicated. In a market in which credits are freely traded, no one is able to significantly manipulate prices, and utilities have an incentive to operate in an efficient manner, the market price is determined by the marginal cost of emissions control for all participants in the market. If this price is lower than the damage cost of emissions, then the government has created too many emission allowances (or not reduced emissions enough) and all utilities will emit more than what would be socially optimal. The opposite is true if the price exceeds the damage cost. In the case of too low a price, a utility would not do the environment any good if it unilaterally decided to reduce emissions further than point P_{15} and sold the excess credits to other utilities. The total emissions by the industry would be the same, but higher than necessary control costs will have been incurred.[6]

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[5] For example, local coal interests have been a significant factor in determining the method of compliance with the acid rain provisions of the 1990 Clean Air Act.

[6] This is the effect of imposing externality adders on SO_2 emissions over and above the cost of allowances (Benjamin F. Hobbs, "Environmental Adders and Emissions Trading: Oil and Water?" *The Electricity Journal* (1992). Utilities subject to such adders will be encouraged to emit less SO_2, freeing up allowances to sell elsewhere. The national emissions remains the same because of the 1990 Act's cap; allowances will simply be reallocated among utilities, while compliance costs will increase. The impact of having the quantity limited or the tax set too high or too low is discussed in Chapter 2 of this report.

Requirements for Considering External Costs

Another means of internalizing environmental costs is for utilities to estimate and consider external costs when making resource acquisition or operation decisions. Environmental impact statements are examples of such requirements. Several states have gone further by specifying particular numerical adders to be considered in the decision calculus (see Chapter 4). The utility does not pay a direct cost, unlike the tax or emission allowance systems, but is forced by regulation to make decisions as if it does (with the resulting higher cost passed through to ratepayers if implemented prudently). The most common version of this requirement in the U.S. applies only to decisions concerning resource acquisition. For our hypothetical utility, this would mean that the "cost," including adders, of new combustion turbines, combined cycle facilities, and coal plants would be increased relative to DSM. In theory, however, adders also could be extended to dispatch and pricing decisions.[7]

If the utility is forced to include external costs in all its resource operation and procurement decisions, the effect would be the same as an emission tax (Figure 6-3). An efficient plan would be chosen, and if the estimated external cost was an accurate estimate of actual damages, the least social cost plan would be achieved.

This outcome is unlikely to occur, however, if external costs are only factored into resource procurement decisions and not into operation. The environmental costs of capacity expansion and DSM programs would be considered, but the utility would dispatch its resources to minimize internal cost. This is inefficient because, as pointed out earlier, efficient alternatives almost always include some degree of emissions dispatch.[8] These

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[7] S. Bernow, B. Biewald, and D. Marron, "Full-Cost Dispatch: Incorporating External Costs in Power System Operations," *The Electricity Journal*, (March 1991); S. Wiel, "The New Environmental Accounting: A Status Report," *The Electricity Journal* 4, no. 9 (1991).

[8] See the previous discussion where Figures 5-1 and 5-4 are compared.

inconsistent incentives can lead to inefficient decisions, such as the adoption of expensive pollution controls when changes in dispatch order would accomplish the same emission reductions at less cost. Thus, just like command-and-control regulations, this policy can result in the choice of an inferior alternative over a superior one.[9] Unfortunately, such inefficient outcomes are likely in those jurisdictions that now require use of quantitative adders in evaluating new resources.

Another example of such an inefficiency is that uneconomic life extension of coal units might be encouraged because such decisions would not be subject to the adders system. Consider three resource options that might be compared by our hypothetical utility:

- construction of 145 MW of combined cycle capacity;
- a load control program that clips 40 MW off the system peak, plus 86 MW (peak) of energy efficiency programs; and
- life extension of a 145 MW coal-fired unit that would otherwise be retired.

Each option is paired with 212 MW of new combustion turbines. The amount of each resource is chosen so that the system achieves a 15 percent reserve margin.

Table 6-1 summarizes the costs and emissions of each resource, based on how they would be dispatched in our hypothetical system. Under least-cost dispatch, the combined cycle would have a capacity factor of 0.29, while the repowered coal unit would have one of 0.85. The table calculates the utility cost per unit of output of the resource, along with the societal cost, assuming for the sake of argument that CO_2 emissions result in \$30 per ton of damages. The table shows that DSM is the least-cost resource either on a total cost basis or dollars-per-MWh basis. Meanwhile, combined cycle capacity is the most costly in terms of dollars per MWh.

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[9] Clinton J. Andrews, "The Marginality of Regulating Marginal Investments: Why We Need a Systemic Perspective on Environmental Externality Adders," *Energy Policy*, May 1992; K.L. Palmer and A.J. Krupnick, "Environmental Costing and Electric Utilities' Planning and Investment," *Resources* 105 (Fall 1991).

TABLE 6-1

PER-UNIT UTILITY AND SOCIETAL COST CALCULATIONS:
THREE-RESOURCE COMPARISON

Resource Option	Annualized Capital Cost, $/yr	Annual Variable Cost, $/yr	CO_2 Produced, tons/yr	Energy Produced or Saved, MWh/yr	Utility Cost of Option, $/MWh	Social Cost of Option (@ $30/ ton), $/MWh
145 MW Combined Cycle, Gas Fired	$13,900,000	$13,400,000	176,000	368,000	$74.2	$88.5
126 MW DSM	$27,000,000	$0	0	385,000	$70.1	$70.1
Repowering of 145 MW Coal Plant	$24,100,000	$22,700,000	1,195,000	1,080,000	$43.3	$75.7

Source: Authors' construct.

However, these results are somewhat misleading because the resources are used differently. Table 6-2 presents the resulting costs and emissions for the *entire system*. It reveals that the combined cycle unit results in the lowest system-wide cost for the utility, mainly because of its dispatching flexibility. The DSM option is most expensive. So, in the absence of an adder or tax on CO_2 emissions, the utility would recommend construction of the combined cycle unit.

However, if a $30 adder was applied to CO_2 emissions from just new resources, and not life extension of existing units, then the decision would be different. Regulators would conclude that DSM was definitely cheaper--whether by the dollars-per-MWh measures of Table 6-1 or the adjusted total dollar figures of Table 6-2.[10] As a result, the combined cycle plant would not be approved. In that case, the utility would decide instead to extend the life of the coal unit, since that decision is not subject to the adders system and has the next lowest utility system cost. If that happens, the result is both higher costs *and* higher emissions than would otherwise be the case.

Although this example is contrived, it illustrates the possibility that adders applied only to new resource additions can make matters worse from both an economic and environmental perspective.

Examples of Efficient Operational Strategies for Environmental Improvement

A major complaint about command-and-control and externality adders is that they provide no incentive for achieving the cost-effective emission reductions that emissions dispatch can provide. The purpose of this section is to illustrate the potential cost of

[10] The adjusted dollar figures include a $30-per-ton penalty for the new combined cycle unit but not for any other generators.

TABLE 6-2

TOTAL UTILITY SYSTEM COST AND SOCIETAL COST CALCULATIONS:
THREE-RESOURCE COMPARISON

Resource option	Utility Cost for Entire System, $/yr	System CO_2 Produced, tons/yr	Adjusted System Cost (including CC CO_2 costs), $/yr	System Societal Cost (@$30/ton), $/yr
145 MW Combined Cycle, Gas Fired	$150,300,000	4,880,000	$155,600,000	$296,700,000
126 MW DSM	$153,600,000	4,660,000	$153,600,000	$293,400,000
Repowering of 145 MW Coal Plant	$152,000,000	5,090,000	$152,000,000*	$304,700,000

Source: Authors' construct.

* Excludes coal plant CO_2 because those emissions are not subject to the CO_2 adder.

emissions dispatch via several case studies. The effects of resource acquisition upon emissions were explored in a number of case studies and are not reviewed here.[11]

Case Study 1: SO_2 Emissions Dispatch by TVA

The 1990 Clean Air Act Amendments encourages SO_2 emissions dispatch because it is a utility's total emissions that matter under the Title IV emissions allowance system. Jackson et al., (1993)[12] describe what they term "soft" strategies that the Tennessee Valley Authority (TVA) will pursue to comply with that title. The utility is implementing an energy management system that makes it possible to optimize unit commitment and dispatch under either an assumed SO_2 allowance price or a cap on emissions.[13]

Figure 6-4 shows approximately how much of an emissions reduction TVA believes it can achieve by emissions dispatch alone. If the price of allowances is $250

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[11] For example, see Clinton J. Andrews, "Spurring Inventiveness by Analyzing Trade-Offs: A Public Look at New England's Electricity Alternatives," *Environmental Impact Assessment Review* 12 (1992); C.J. Andrews and S.R. Conners, "Cost-Effective Emissions Reductions: Combining New England's Options into a Coordinated Strategy," Presented at the Twelfth Annual North American Conference of the International Association for Energy Economics, Ottawa, Canada, October 2, 1990; J.F. Busch and F.L. Krause, "Environmental Externality Surcharges in Power System Planning: A Case Study of New England," *IEEE Transactions on Power Systems* 8, no. 3 (August 1993); Palmer and Krupnick. "Environmental Costing and Electric Utilities' Planning and Investment;" K. Wulfsberg, "Incorporating Environmental Externalities in the Electric Utility Resource Planning Process: Methods, Effects, and Limitations," M.S. Thesis in Technology and Policy, Massachusetts Institute of Technology, Cambridge, Massachusetts, 1990.

[12] T.M. Jackson et al., "Evaluating Soft Strategies for Clean-Air Compliance," *IEEE Computer Applications in Power* 6 (April 1993).

[13] Southern Company has developed a similar system; see A.A. El-Keib, H. Ma, and J.L. Hart, "Economic Dispatch in View of the Clean Air Act of 1990," *IEEE Transactions on Power Systems* (in press).

Fig. 6-4. Incremental cost of emissions reduction by emissions dispatch for TVA (Source: derived from data in Jackson et al., "Evaluating Soft Strategies for Clean-Air Compliance," 1993).

per ton, the utility would reduce its emissions by 10 percent (from 42,000 to 37,500 tons per month). It would earn $700,000 per month in net revenue from selling the allowances that emissions dispatch could free up.[14]

[14] But for many utilities, the "underutilization" or "minimum burn" constraint imposed by Title IV of the 1990 Act may significantly constrain emissions dispatch during phase I of the Act's acid rain control program (1995-1999) (Benjamin F. Hobbs, "Emissions Dispatch under

Case Study 2: NO_x Emissions Dispatch in the San Francisco Bay Region

Smog episodes in the San Francisco Bay region occur sporadically. Ozone concentrations exceed ambient standards about fifteen days per year. Ozone is the result of photochemical reactions of volatile organic chemicals and NO_x, most of which is emitted by vehicles. However, fossil-fueled power plants also emit NO_x. In an effort to bring the region into attainment for ozone, environmental regulators in California are considering requiring retrofits of selective catalytic reduction (SCR) on some of the area's power plants. This capital-intensive control measure would reduce emissions year round.

An alternative approach is intermittent controls, in which emissions dispatch is used to decrease NO_x emissions. Marnay (1993)[15] proposes that a tax be levied on utility NO_x emissions just during the fifty-day smog season. He examined the effectiveness of such a proposal using a unit commitment model. Assuming conservatively that no additional power can be imported into the area, he concluded that emissions dispatch can lower the utility's NO_x emissions by about 5 percent at a per ton expense that is 40 percent or less of the cost of SCR.[16]

Figure 6-5 summarizes some of the results of this analysis in the form of a distribution of utility NO_x emissions. The right-most distribution shows that without any tax, NO_x emissions would average about 2,250 tons per month. But if a tax is applied, the distribution shifts to the left. For instance, a tax of $100 per pound results in an average

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the Underutilization Provision of the 1990 U.S. Clean Air Act Amendments: Models and Analysis," *IEEE Transactions on Power Systems* 8 (February 1993).

[15] C. Marnay, "Intermittent Electrical Dispatch Penalties for Air Quality Improvement," Ph.D. Dissertation, University of California, Berkeley, California, 1993.

[16] If additional power could be imported, then in general more local emissions reductions would be accomplished under a given NO_x penalty.

decrease of about 100 tons per month. Although emissions dispatch may be insufficient by itself to achieve compliance, it can help the utility avoid some investment

Fig. 6-5. Distribution of NO_x emissions in San Francisco Bay area under different NO_x dispatch penalties (Source: Chris Marnay, "Intermittent Electrical Dispatch Penalties for Air Quality Improvement").

in SCR. The optimal compliance strategy is undoubtedly a combination of SCR, emissions dispatch, and, in the long run, changes in resource mix. The benefits of such a mixed strategy can be realized only if regulators penalize existing emissions using a tax or allowance system;

a command-and-control or adder approach is unlikely to give the flexibility that the utility needs to achieve a least-cost solution.

Case Study 3: Using Externality Adders for Dispatch in New England

Since the publication of Bernow et al. (1991) and Browne (1991),[17] there has been a debate about which emission reductions are possible and what cost increases might occur if externality adders are used to dispatch all generating facilities. Busch and Krause (1993)[18] recently investigated that question for New England using a sophisticated production costing model that accounts for unit commitment targets, must run constraints, and other operating restrictions. They applied Massachusetts' adders for SO_2, NO_x, and CO_2 as dispatch penalties. These penalties were: $1,762 per ton for SO_2, $6,766 per ton for NO_x, and $24 per ton for CO_2 (all expressed in 1990 dollars). As a result of these adders, coal fired power plants were assessed a penalty of between 0.061 and 0.078 dollars per kWh. Penalties for other types of plants are less. The effect of these adders upon operation of the region's power system was evaluated for the years 1990 and 2005.

The emissions impact of those adders are shown in Figure 6-6. The emission reductions are surprisingly modest, given the size of the adders. SO_2 emissions fall by 14 percent, while NO_x decreases by 8 percent to 14 percent. However, CO_2 emissions actually increase in the year 2005. This was apparently because of the dramatically increased utilization of combined cycle plants at the expense of coal and oil steam generation and the increased use of pumped storage (which inflated energy demands, and thus emissions).

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[17] Bernow et al., "Full-Cost Dispatch: Incorporating External Costs in Power System Operations;" G. Browne, "A Utility View of Externalities: Evolution, Not Revolution," *The Electricity Journal* 4, no. 2 (March 1991): 34-39.

[18] J.F. Busch and F.L. Krause, "Environmental Externality Surcharges in Power System Planning: A Case Study of New England," *IEEE Transactions on Power Systems* 8, no. 3 (August 1993): 789-95.

Emissions of SO_2 are of less interest than the decrease in NO_x because Massachusetts revised its adder system in 1992 so that adders do not apply to the SO_2 emissions of any plant that has to acquire allowances. NO_x will be the major air

Fig. 6-6. Effect of emissions dispatch upon emissions in New England (Source: derived from data in Busch and Krause, "Environmental Externality Surcharges in Power System Planning: A Case Study of New England").

pollutant of concern for northeastern electric utilities in the near future. Thus, the study's conclusion that emissions dispatch can make a dent in NO_x emissions is worth noting by the region's regulators.

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CHAPTER 7

THE ROLE OF STATE PUBLIC UTILITY COMMISSIONS IN ENVIRONMENTAL REGULATION: ADAPTING TO A CHANGING REGULATORY CLIMATE

State public utility commissions, in an effort to be proactive concerning the environment, are likely to continue their efforts to internalize environmental costs. With passage of the Energy Policy Act of 1992, which is intended to encourage more competition in electric generation and transmission and the continued use of least-cost and integrated resource planning by state commissions, the debate on the role of the public utility commissions in environmental regulation is likely to persist. As discussed in Chapters 1 and 4, commissions are using qualitative or quantitative considerations applied during the resource selection process (IRP-type process). However, there may be several limits on state commission's abilities to be proactive on the environment in a unilateral way. These limits suggest a more cooperative role for commissions in working with state and federal environmental regulators, state energy or natural resource agency representatives, and legislators.

Need for Cooperative Action on the Environment

It is clear that environmental programs that affect only new resources, such as adders, are less effective and are a more costly means of environmental control when compared to other methods. Methods that apply to just new resources can only have a marginal impact on existing environmental damage.[1] Also, as discussed in Chapters 5 and 6, methods that impact

[1] Clinton J. Andrews, "The Marginality of Regulating Marginal Investments: Why We Need a Systemic Perspective on Environmental Externality Adders," *Energy Policy* (May 1992): 450-63.

system operations and existing emissions and encourage more efficient operation are more cost-effective; that is, have a lower cost per unit (tons, pounds, and so on) removed. The most cost-effective pollution-control strategies are a mix of dispatch changes, emission controls, fuel changes and, lastly, resource additions. Environmental programs that can encourage utilities to adopt these control strategies include emission taxes and emission limits with trading. However, state commission authority to implement programs that affect existing emissions or that require reductions beyond federal mandates is uncertain.[2]

State regulations that exceed federal mandates are permitted provided (1) Congress did not specifically preempt state action, (2) the state regulation is not found to violate the Commerce Clause of the Constitution, and (3) the state regulation is not in conflict with a pervasive federal statutory scheme.[3] With respect to environmental regulation, Congress has not explicitly preempted states from taking additional action. Recent court decisions have indicated that, absent a clear congressional intent, states exercising their historic police powers of guaranteeing public health and safety will generally not be preempted.[4]

What is less certain is that with electricity increasingly becoming an interstate commodity, future state action that exceeds the federal mandate may be subject to legal challenges based on a Commerce Clause violation. In this case, an argument for regional or national uniform standards could be made, even if the regulation was aimed at local issues.[5] When deciding such cases, the courts balance local concerns with their affect on interstate commerce, upholding the state regulation when it is not deemed excessive (using a "burdens and benefits" test). Courts, however, at times defer to a

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[2] Paul A. Agathen (an attorney with an electric utility) in "Dealing with Environmental Externalities," *Public Utilities Fortnightly* (February 15, 1992): 23-24, asks "what right does a public service commission have to order. . .a utility [to] reduce pollution beyond what [the pollution] laws require?" He then notes, "[a]ssuming the utility was not violating the pollution laws to begin with, this is tantamount to ordering it to raise rates in order to reduce pollution below the limits adopted by our elected officials."

[3] Sinozich et al., "Preemption in Administrative Law," 45 *Admin. L. Rev.* 111 (1993).

[4] Id., at 124.

[5] Id., at 127.

federal agency's determination since it is believed they are better qualified than the courts to make such determinations.[6] Even if it is assumed that states are allowed to exceed federal mandates, the question would remain as to which state agency within the state is best equipped to develop and implement state and federal environmental policy.

States usually grant authority to directly regulate emissions to an environmental agency. State utility commissions, because of their utility oversight and ratemaking authority, have thus far only considered environmental consequences of new resource options. Under their existing authority, state commissions may also attempt to more directly influence existing emissions (such as through an incentive system described in Chapter 3). Before deciding the type of action (if any) to take concerning the environment, commissions should consider at least three factors: (1) their authority within their state to regulate environmental impacts, (2) the role different state agencies play in the determination, development, and implementation of environmental regulations and the commission's most effective role, and (3) the inherently limited scope of the commission's influence on polluting sources. The first issue, in-state authority, is clearly a state-specific issue. As described in Chapter 4, some commissions have decided to consider environmental impacts while others have decided against doing so.

The second consideration is to determine which agency is best equipped to manage environmental regulation in the state and what the commission's role should be. Commissions usually have an advantage in terms of being able to analyze emission-reduction options and control costs, and instituting policies that affect utility behavior. They also are in a better position to encourage utilities to implement environmental programs in an effective manner through their ratemaking authority and have better access and understanding of utility options and costs. Environmental regulators, on the other hand, clearly have an advantage with

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[6] Id., at 120-1, 223-4.

respect to calculating social costs[7] and authority to implement more efficient market-based environmental programs. They also have better access to environmental damage information, are more acquainted with existing environmental requirements and possible new options, and are in a better position to institute cost-effective programs that address existing emissions.

The third consideration, scope of influence, is based on the fact that even with broader environmental authority, commissions regulate only utilities and not other sources in the state. For certain pollutants electric utilities are a significant and sometimes the largest single source of a pollutant in an area; for other pollutants, they are a relatively minor contributor compared to other sectors.[8] Other sources of pollution, beyond the control of the commission, may have lower control costs than electric utilities. Environmental regulators have a wider authority to consider all sources and can choose from a wider range of appropriate control policies. This can prevent unfairly burdening electric utilities, that is, causing them to incur higher control costs when alternative lower-cost sources are available. In some cases, such as CO_2 or SO_2, national environmental regulations are necessary to prevent any one state from imposing environmental costs on others and also to distribute the costs of emission reductions fairly across states. The more comprehensive the environmental regulations, the greater the opportunities to make them cost effective and fair.

This asymmetry of authority and information suggests that the best approach may be a cooperative one, where the two agencies exchange information and work together to develop and implement environmental programs. Commissions, in order to have an impact on existing emissions in a cost-effective and timely manner, could cooperate with the

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[7] Of course, commissions could develop this expertise also, but only at a high cost since they do not, in general, currently have this capability.

[8] For example, nationally, electric utilities account for about 35 percent of CO_2 emissions from energy consumption sources and less than 4 percent of nitrous oxide emissions (*Emissions of Greenhouse Gases in the United States, 1985-1990* DOE/EIA-0573 (Washington, D.C.: Energy Information Administration, U.S. Department of Energy, September 1993), calculated from tables 7, 8, 35, and 39).

environmental agencies in their state to develop and implement appropriate programs. Historically, with some exceptions, these two state agencies have not always coordinated their efforts well.[9] Also, many of these programs would require multistate cooperation, something that also is without a great deal of precedent in this industry.[10] However, the potential environmental benefit and cost savings that could occur from such cooperation could be considerable and worth the effort to pursue.

It may be more beneficial to ratepayers for commissions to direct their efforts towards assisting the development of market-based environmental policies, including emission taxes and trading programs. The cost-effectiveness of market-based programs is highly dependent on the policies of state commissions. This would include adjusting regulatory and ratemaking policies to encourage utilities to use these programs to minimize their compliance costs. This makes it more likely that the cost saving potential of market-based programs is realized.

As discussed in several previous sections of this report, emission taxes and trading systems to reduce emissions, are able to achieve the desired emissions level at a lower cost than command-and-control or adder programs. Current environmental policy is a combination of command-and-control, taxes,[11] and emissions trading and offset programs at

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[9] Douglas N. Jones and Richard A. Tybout, "Environmental Regulation and Electric Utility Regulation: Compatibility and Conflict," *Environmental Affairs Law Review* 14, no. 1 (1986): 31-59.

[10] For a discussion of two exceptions see Chapter 4, "Two Major Regional Initiatives and the FERC," in Douglas N. Jones et al., *Regional Regulation of Public Utilities: Opportunities and Obstacles* (Columbus, OH: The National Regulatory Research Institute, December 1992). Also, *Utility Environmental Impacts: Incentives and Opportunities for Policy Coordination in the New England Region* (Boston, MA: Project on Regional Coordination and Environmental Externalities, June 1994), discusses that region's coordination of state commission environmental actions.

[11] Thomas A. Barthold, "Issues in the Design of Environmental Excise Taxes," *Journal of Economic Perspectives* 8, no. 1 (Winter 1994): 133-151, provides a list of current federal tax provisions that have environmental consequences, although the environment may not be the primary purpose of a tax and its effect may be less than perfect. Examples of a Pigouvian emission tax are rare in the U.S.; one may be the tax on ozone-depleting chemicals (see the discussion in Barthold, n. 4 and pp. 136-38).

both the state and federal level. Currently, there are initiatives by environmental regulators (discussed in Chapter 3) to institute more market-based environmental programs. These include the Clean Air Act's allowance trading program, California's South Coast Air Quality Management District emissions offset program, the eight states' program for the northeast NESCAUM region, as well as other trading systems currently being considered.

Preliminary indications are that the national trading system for SO_2 emissions is developing and has demonstrated that these types of programs can work in the electric industry and can be beneficial. However, there are also indications that the cost savings potential of the SO_2 trading system is not currently being fully realized.[12] Reasons for this include state legislative action that limited utility options, the negative treatment in the press of the first trades, and utility reluctance to use a novel and untried means of compliance. Perhaps the most significant factor is that public utility commissions have not encouraged their jurisdictional utilities to take advantage of the opportunities that are presented by the allowance system.[13] Therefore, more consideration should be given to commission actions that encourage utilities to take advantage of this and other trading systems. The results will be a lower cost of compliance and lower utility rates for consumers. Moreover, using the analysis presented in Chapter 2, a downward shift of the marginal-control cost curve (because

[12] K. Rose, A. Taylor, and M. Harunuzzaman, *Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowances* (Columbus, OH: The National Regulatory Research Institute, 1993), Chapter 2.

[13] Douglas R. Bohi, "Utilities and State Regulators Are Failing to Take Advantage of Emission Allowance Trading," *The Electricity Journal* 7, no. 2 (March 1994).

of inducements from commissions to encourage cost-minimizing utility behavior[14]) results in more emission reductions being feasible.[15]

This provides further rationale for state commissions to consider working with the environmental regulators to implement existing environmental programs and develop new ones rather than instituting their own programs. Commissions may consider concentrating their efforts on the cost-effective implementation of existing environmental regulation[16] instead of duplicating or attempting to supplement the environmental regulators' efforts. This includes working with their respective state environmental regulatory agency and the federal EPA as well as state and federal legislators to develop more effective environmental regulation.

Some Implementation Considerations

Since state commissions usually do not have access to or expertise in determining social cost, they often turn to control cost methods. The argument for this method is that, while it may not be ideal, it provides a proxy value based on society's "willingness to pay." This value is determined through the political process and resulting legislation. The control cost, however, bears no relationship to the social cost of emissions or marginal benefit from

[14] A discussion of the relative merits of cost-of-service regulation and an incentive mechanism to induce cost-minimizing behavior is in Kenneth Rose, "Regulatory Treatment of Allowances and Compliance Costs: What's Good for Ratepayers, Utilities, and the Allowance Market," in *Regulatory Policy Issues and the Clean Air Act: Issues and Papers from the State Implementation Workshops*, eds., Kenneth Rose and Robert E. Burns (Columbus, OH: The National Regulatory Research Institute, July 1993).

[15] It is believed that because of the expected cost savings associated with the SO_2 trading program, more emission reductions were mandated in Title IV of the Clean Air Act than if it was a command-and-control program.

[16] This includes adjusting ratemaking procedures for both command-and-control, still the most common form of environmental regulation, as well as market-based programs. This is because utilities may not have an incentive to minimize the cost of complying with either type of environmental program under cost-based regulation.

emission reductions. The control cost for a given level of reduction provides the cost *at that point*, not the cost of further reductions. Also, using a current cost-of-control or emission-credit price for existing environmental regulations "double counts" the already internalized cost. These methods, while comparatively easy, are not a good substitute for social-cost studies.

Given this mix of existing environmental regulations, it has been suggested that commissions determine an "optimal adder," based on the marginal damage after environmental regulations were accounted for.[17] This optimal adder would take existing environmental regulation into account and be based on remaining external costs. It is doubtful, however, that many public utility commissions are equipped to determine the optimal adder due to the nature and the substantial amount of information that would be required.

Advocates for public utility commission environmental programs sometimes note that while the precise value of an adder or tax is not known, they believe it is not zero. They then conclude that even though precise values of the social cost are not known, it is some positive number; therefore, some positive number is better than nothing. Whether this is true or not depends on the relationship between the actual optimal tax (which is unknown) and the value of the tax (or adder) that is selected. (Using the graphical analysis presented in Chapter 2, an example can be constructed that demonstrates this is not always the case.) In Figure 7-1 the tax is set at f when f^* is the optimal tax. Note that the actual tax is only about 10 percent higher than the optimal. The welfare loss of doing nothing is the area represented by G and is less than the loss caused by setting it at f, which is represented by the area H.[18]

This does not, of course, suggest that in every case no action is better or no action should be taken to improve the environment; it only suggests that the penalty of getting it

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[17] A. Myrick Freeman III, et al., *Accounting for Environmental Costs in Electric Utility Resource Supply Planning*, Discussion Paper QE92-14 (Washington, D.C.: Resources for the Future, April 1992).

[18] This comes about because of the relative slopes of the two curves. Of course, an example can be drawn that shows the opposite case, where no action has a larger welfare loss than more emission reduction than the optimal.

wrong can be severe and that the "something is better than nothing" argument does not always hold. Care should be taken, therefore, to not cause more harm than good when instituting even well-intended public policy. The goal of environmental policy is not necessarily to drive all emissions to zero (except perhaps some substances that are toxic low levels), but to balance the marginal benefit to society (when not considered by the unregulated market) with the marginal cost of control. This can only be determined through careful consideration of both the costs and benefits.

Cropper and Oates note that more careful economic analysis may be more necessary now after environmental progress has been made than was needed earlier in the "environmental revolution."[19] To illustrate their point, consider the marginal-

[19] Maureen L. Cropper and Wallace E. Oates, "Environmental Economics: A Survey," *Journal of Economic Literature* 30 (June 1992): 730.

Fig. 7-1. Hypothetical example of the social welfare loss from taking no action compared with an emission tax that is set above the optimal (Source: Authors' construct, based on William J. Baumol and Wallace E. Oates, *The Theory of Environmental Policy*, 2nd ed. (Cambridge, England: Cambridge University Press, 1988)).

control cost curve in Figure 7-2. This marginal cost curve has a flat region and then rises at an increasing rate as emission reductions increase.[20] With some slight environmental regulation already in place, a doubling of emission reductions from q_1 to q_2 results in no change in the marginal cost (total cost, of course, would increase).

[20] Control options are usually characterized as being "lumpy," that is, there are discontinuous jumps in costs as reductions increase. This is a smoothed but fair representation of what the marginal cost curve probably looks like for many pollutants.

Fig. 7-2. Hypothetical marginal-control cost curve and four levels of reduction (Source: Authors' construct, based on Cropper and Oates, "Environmental Economics: A Survey" 730.

However, if the current environmental standard is already more strict, at q_3, and new regulations are being considered to move to q_4, the consequence is far more significant; the marginal cost increases from MC_3 to MC_4. If the marginal social-benefit curve is MSB_1 and intersects the marginal cost curve at q_4, then the proposed regulation is justified and should be taken. If, on the other hand, q_3 was already the optimal reduction because marginal social benefit is MSB_2, then a social welfare loss would result (the area ABC) from the further reduction.

Position on the curve depends on the existing level of environmental regulations and the pollutant being controlled. For example, there are currently no requirements to reduce CO_2 but considerable NO_x requirements. This will also be very sector-specific; the electric utility industry, for example, may (again, depending on the pollutant) have relatively more environmental requirements than the transportation sector.

As noted, state and federal environmental regulators are in a better position in terms of expertise to conduct a careful analysis to determine environmental benefit from emission reductions required to avoid large welfare losses. Also, in terms of authority, environmental regulators can institute more efficient regulations to reduce emissions. The economic regulator may have an advantage in terms of determining the marginal cost of control, determining where utilities are on the marginal cost curve, and encouraging utilities to minimize their costs when implementing environmental regulations. This again suggests that cooperation between economic and environmental regulators may be the best regulatory strategy.

The Changing Industry and Regulatory Structure

More and more frequently, questions have been raised as to the future role of IRP in an increasingly competitive electric service industry.[21] The question then is, What type of environmental policy is more compatible with a more competitive industry? With more independent power, more wholesale wheeling, and the possibility of retail wheeling, state commissions may have less control over new resources as a competitive market develops.

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[21] See for example, Paul L. Joskow, "Emerging Conflicts Between Competition, Conservation and Environmental Policies in the Electric Power Industry," Keynote Address for the Public Utility Research Center's conference on competition in regulated industries, University of Florida, April 29-30, 1993; Bernard S. Black and Richard J. Pierce, Jr., "The Choice Between Markets and Central Planning in Regulating the U.S. Electric Industry," Draft, unpublished paper, Columbia Law School, New York, June 1993; and Kenneth Rose, "Planning Versus Competition and Incentives: Conflicts, Complements, or Evolution?" in *Reforming Electricity Regulation: Fitting Regional Networks into a Federal System*, Clinton J. Andrews, ed. (Westport, CT: Quorum Books, forthcoming).

Environmental regulators, on the other hand, will likely continue to be charged with the responsibility of environmental management. Emission limits with trading may be an especially appropriate means of emission control in a competitive environment where there are multiple sources under different jurisdictions (Federal Energy Regulatory Commission, multiple state commissions, other state and federal agencies).

This does not suggest a diminished role for state commissions in environmental management but suggests an evolving one. As mentioned, this new role will require more cooperation with environmental regulators and more regional considerations. It will also be a challenge to commissions to adjust regulatory practices to encourage utilities that remain under their jurisdiction to comply with environmental requirements in a cost-effective manner.

More research needs to be conducted to determine the effect on the environment from a more competitive industry structure and to identify the types of regulatory institutions and policies that may be necessary to meet environmental and other energy policy objectives. Currently, there is considerable focus on the possible negative impacts of competition.[22] However, a comprehensive analysis would not only consider the possibility of less utility-sponsored DSM, but also consider the positive effects from utilities and other suppliers receiving more incentive to operate their systems more efficiently to minimize costs and remain competitive than what would occur under cost-based regulation. This will undoubtedly be an area of fruitful future research.

[22] See for example, Armond Cohen and Steven Kihm, "The Political Economy of Retail Wheeling, or How to *Not* Re-Fight the Last War," *The Electricity Journal* 7, no. 3 (April 1994): 49-61.

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APPENDIX A

A SIMPLE LINEAR PROGRAMMING IRP MODEL

A linear programming (LP) model to optimize the mix of resource acquisition and generation dispatch, based upon the generation model of Turvey and Anderson (1977);[1] see also Lee et al. (1979)[2] or Meier (1984).[3] The formulation of any optimization model consists of a description of its decision variables, objective(s), and constraints. Lower case letters designate decision variables, and capital letters define fixed parameters supplied by the analyst. Let the three basic decision variables of our model be:

x_i = the generation capacity [MW] of supply resource i, $i = 1,2,..,I$. Supply resources can include not only utility-owned generation plants but also purchases from other utilities or independent generators of power. For existing plants, the value of this variable is fixed and is not altered in the LP.

g_{it} = MW output during subperiod t, t=1,2,..,T of supply resource i. The 8760 hours in each year are divided into T demand periods. The first period represents peak demand, while the last period T is the lowest demand period. Commonly, these models include three to six periods; additional periods generally contribute little to model accuracy. This variable was modified for the cofired generating unit to allow the unit to choose between using 100 percent coal and 85 percent coal/15 percent natural gas.

d_k = 1 if DSM program k is fully implemented, $k=1,2,..K$. Intermediate values between 0 and 1 represent partial implementation.

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[1] R. Turvey and D. Anderson, *Electricity Economics: Essays and Case Studies* (Baltimore, MD: The Johns Hopkins University, 1977), chapter 13.

[2] S. Lee, N. Stoughton, and N. Badertscher, *Comparative Analysis of Generation Planning Models for Application to Regional Power System Planning*, Prepared for U.S. Department of Energy (Palo Alto, CA: Systems Control, Inc., 1979).

[3] P. Meier, *Energy Systems Analysis for Developing Countries* (New York: Springer-Verlag, 1984).

The objective is to minimize the annual worth of capital (levelized costs) and operating costs:

$$Min\ Cost = S_{i=1,2,..,I}\ CRF\ CX_i\, x_i + S_{k=1,2,..,K}\ CRF{*}CD_i\, d_k$$

$$+\ S_{i=1,2,..,I}\ S_{t=1,2,..,T}\, H_t\, (CG_{it} + PEN{*}CO2_{it})\, g_{it}$$

[Capital Costs] [Operating Costs + CO_2 Tax or Penalty]

where the fixed parameters are as follows:

CD_k = capital and other fixed costs [$] of fully implementing DSM program *k*.

$CO2_{it}$ = CO_2 emissions [tons per MWh] of generation from unit *i* during subperiod *t*. This is the product of the unit's heat rate and the CO_2 resulting from burning one unit of fuel.

CRF = capital recovery factor [one per year] used to annualize capital costs.

CX_i = capital and other fixed costs [dollars per MW] of building capacity of type *i*. In general, this parameter should include the present worth of the resource's fixed operations and maintenance costs, while deducting the resource's salvage value at the end of the planning period. For existing plants, this cost is omitted, as their capacity is fixed.

CG_{it} = the present worth of the variable operating cost [dollars per MW per hour] during subperiod *t* of supply type *i*. This cost includes fuel and any miscellaneous variable operating costs:

$$CG_{ivyt} = HR_{it}\, FC_{it} + VO\&M_{it}$$

where HR_{it} is the unit's heat rate [fuel energy per kWh], FC_{it} is the fuel cost [dollars per fuel energy], and $VO\&M_{it}$ is the nonfuel variable O&M cost. For some supply resources, variable costs may be the same in all *t* of a given year, but for others, costs may vary due to temperature-dependant heat rates or seasonal variations in fuel prices.

H_t = the number of hours in time period t.

PEN = dollars-per-ton tax or penalty applied to CO_2 emissions. If the values of all x_i and d_k are fixed, then this results in emissions dispatch. If, on the other hand, those capacity resources are allowed to vary, then the mix of resources would be chosen to minimize the utility's cost plus CO_2 taxes.

Demand, operating, and reliability constraints restrict which values of the decision variables can be chosen. Simple yet typical formulations of these constraints are given below. Consistent with standard mathematical programming notation, terms involving decision variables are on the left hand side of the equation, and constants are placed on the right.

- *Load must be met in each subperiod t of each year y:*

  $$S_{i=1,2,..,I}\, g_{it} - S_{k=1,2,..,K}\, SAV_{kt}\, d_k \geq LOAD_t \quad \textit{for all } t$$

  where $LOAD_t$ is the MW load during t, including transmission and distribution losses, and SAV_{kt} is the MW savings resulting from fully implementing DSM program *k*. This constraint states that the sum of the MW output in subperiod *t* from all plants must equal or exceed the electricity demanded $LOAD_t$ at that time, as modified by any DSM programs.

- *Generation must be less than derated capacity for each resource in each t and y:*

  $$g_{it} - (1 - FOR_i)x_i \leq 0 \quad \text{for all } i \text{ and } t=1,2,..,T\text{-}1$$

  where FOR_i is the forced or unplanned outage rate of resource *i*. This constraint is not needed for the time of lowest demand (subperiod *T*), as long as the annual energy constraint described next is also imposed. If the resource is an existing plant, then x_i is fixed and its term is instead placed on the right side of the equation.

- *Annual energy constraint for each resource:*

  $$S_{t=1,2,..,T}\, H_t\, g_{it} - CF_i x_i \leq 0 \quad \textit{for all } i$$

  where CF_i is the maximum possible capacity factor (output/capacity) for resource *i*. Again, for existing resources, x_i is a constant and instead appears on the right side of the equation.

- Reserve margin constraint:

  $S_{i=1,2,..,I}\, x_i + S_{k=1,2,..,K}\, SAV_{kPEAK}\, d_k + \geq LOAD_{PEAK}\, (1+M)$

  where $LOAD_y$ is the yearly peak demand, and M is the desired reserve margin.

- *Upper bound on new capacity:*

  $x_i \leq X_{iMAX}$ *for all i*

  This constraint allows additions to be no more than a predetermined maximum size X_{iMAX}.

- *Upper bound on DSM programs:*

  $d_k \leq 1$ *for all k*

- Nonnegativity restrictions for all variables:

  $x_i \geq 0$ *for all i*; $g_{it} \geq 0$ *for all i and t;* $d_k \geq 0$ *for all k*

Once the model is formulated and its parameter values estimated, then it can be inserted into standard linear programming software and solved. The solution consists of the best values of the decision variables and the resulting total cost.

Plans A through D in Chapter 5 were generated by varying *PEN* from \$0 to \$30 per ton, and noting the resulting optimal values of x_i and d_k. Varying degrees of emissions dispatch were simulated for those solutions by fixing the values of x_i and d_k at their optimal values, and then using the model to dispatch the plants (g_{it}) under a range of values of *PEN*. The other plans (E, F, and G) were obtained by assuming a certain mix of plants and DSM programs (i.e., fixing the values of x_i and d_k) and then using the model to dispatch those resources under various values of *PEN*.

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APPENDIX B

ASSUMPTIONS FOR THE ENVIRONMENTAL IRP EXAMPLE

Tables B-1 through B-3 detail the assumptions made in the linear programming IRP model.

TABLE B-1

MISCELLANEOUS DATA FOR
LINEAR PROGRAMMING EXAMPLE

Parameter	Value
Minimum Reserve Margin, M	15 percent
Maximum Additional Capacity of a Single Type, X_{i1MAX}	400 MW
Capital Recovery Factor for Plant Investment	12 percent per year
Load Block Widths H_t, t=1,2,3,4,5	100, 620, 1950, 2545, 3545 hours
Load Block Heights $LOAD_{1t}$, t=1,2,3,4,5	1050, 950, 825, 525, 275 MW
Coal Cost, CO_2 Emissions	$1.60 per mmBtu, 221 pounds per mmBtu
Natural Gas Cost, CO_2 Emissions	$3.80 per mmBtu, 116 pounds per mmBtu
Heavy Fuel Oil Cost	$2.60 per mmBtu, 168 pounds per mmBtu

TABLE B-2

GENERATING UNIT DATA, LINEAR PROGRAMMING IRP MODEL

Plant *i*	Type	Capacity MW	Must Run Capacity MW	Heat Rate Btu/ kWh	Nonfuel Variable O&M $/MWh	Capital Cost $/kW	Forced Outage Rate	Maximum Capacity Factor
A	Existing Coal 1 (Scrubbers)	200	80	10,000	9	n.a.	0.05	0.85
B	Existing Oil Steam	150	0	10,200	3	n.a.	0.04	0.85
C	Existing Combustion Turbines	200	0	13,800	9	n.a.	0.035	0.8
D	Existing Coal 2	150	60	10,400	5	n.a.	0.05	0.85
E	Existing Coal 3	150	0	11,500	5	n.a.	0.05	0.85
F	New Coal Plant	200 (max)	80	10,000	5	1000	0.05	0.85
G	New Combined Cycle	500 (max)	0	8,230	5	800	0.05	0.85
H	New Combustion Turbine	500 (max)	0	13,800	8	550	0.035	0.8
i	Install 15 percent Natural Gas Cofire	n.a.	80	10,400	3	9	0.05	0.85

	Capability, Coal 2							

Note: n.a. = Not Applicable

TABLE B-3

DEMAND SIDE PROGRAM CHARACTERISTICS, LINEAR PROGRAMMING IRP MODEL

Program k	Type	Load Decrease by Subperiod *t*	Cost
A	Energy efficiency	40.0, 36.2, 31.4, 20.0, 10.5 MW	$55/MWh
B	Energy efficiency	40.0, 36.2, 31.4, 20.0, 10.5 MW	$65/MWh
C	Energy efficiency	40.0, 36.2, 31.4, 20.0, 10.5 MW	$75/MWh
D	Load control	40 MW peak only (no energy savings)	$800/Peak kW

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