REPORT OF THE

# VIRGINIA COAL AND ENERGY COMMISSION

TO THE GOVERNOR AND
THE GENERAL ASSEMBLY OF VIRGINIA

# SENATE DOCUMENT NO. 34

COMMONWEALTH OF VIRGINIA
RICHMOND
1996

## MEMBERS OF THE COMMISSION

Senator Frank W. Nolen, Chairman
Delegate J. Paul Councill, Jr., Vice Chairman
Senator Charles J. Colgan
Senator H. Russell Potts, Jr.
Senator Jackson E. Reasor, Jr.
Senator William C. Wampler, Jr.
Delegate Watkins M. Abbitt, Jr.
Delegate James F. Almand
Delegate George W. Grayson
Delegate Harry J. Parrish
Delegate Jackie T. Stump
Delegate A. Victor Thomas
Delegate John Watkins
H. Kim Anderson
Donald B. Baker
Ronald J. Des Roches
Laura Bateman Hehner
W. Thomas Hudson
Lloyd Robinette
Richard A. Wolfe, Ph.D.

## STAFF

DIVISION OF LEGISLATIVE SERVICES

Arlen K. Bolstad, Senior Attorney
Nicole R. Beyer, Staff Attorney
Cynthia G. Liddy, Senior Operations Staff Assistant

SENATE COMMITTEE OPERATIONS

Thomas C. Gilman, Jr., Chief Committee Clerk

# Table of Contents

APPENDICES

**Report of the**
**Virginia Coal and Energy Commission**
**to**
**The Governor and the**
**General Assembly of Virginia**
**Richmond, Virginia**
**1996**

TO: The Honorable George F. Allen, Governor,
and
The General Assembly of Virginia

## I. INTRODUCTION

The Virginia Coal and Energy Commission studies coal as an energy resource and promotes the development of renewable and alternative energy resources other than petroleum. This legislative commission is a 20-member body comprised of 12 legislators (six from the House and six from the Senate) and eight citizen members. Commission meetings in 1995 were convened in Blacksburg and Abingdon, with a concluding meeting in Richmond immediately prior to the 1996 Session of the Virginia General Assembly.

**Coal production tax credits.**

The Commission's 1995 activities focused principally on Southwest Virginia's declining coal industry. Legislation passed by the 1995 Session of the General Assembly provided some tax relief to Virginia's coal producers in the form of production tax credits, but the legislation contained conditions and contingencies that delayed and minimized the program's potential benefits. The Commission's coal subcommittee was directed by the 1995 Session of the General Assembly (pursuant to House Joint Resolution 586) to continue its study of methods to reverse the downward trend in coal production and employment. The subcommittee's chief agenda item was further review of the 1995 legislation with a view toward 1996 amendments strengthening the measure.

The coal subcommittee ultimately recommended, and the Commission endorsed, amendments to the 1995 tax credit legislation that were incorporated into Senate Bill 539 and House Bill 1454 introduced in the 1996 Session. House Bill 1454 was enacted by the 1996 Session and signed by the Governor. Its provisions make the tax credits available immediately; coal producers can file for these credits on their 1996 returns. The bill also eliminated a provision in the 1995 bill making the availability of the credits in any year contingent upon general fund revenues exceeding official projections by at least the cost of the credits. Finally, increases to the legislation's key components, such as the seam thickness credits, doubled the likely benefit to the coal producers from approximately $15 million to $30 million in annual tax savings.

**Low-income energy assistance programs.**

The Commission also endorsed legislation recommended by its Energy Preparedness Subcommittee. During its annual review of low-income energy assistance programs available to the Commonwealth, the subcommittee concluded that the heating fuel assistance and home weatherization programs should be better coordinated. The subcommittee members learned that federal law governing funding for fuel assistance program permitted reallocation of up to 25 percent of Virginia's fuel assistance block grant to weatherization programs. Following extensive discussions between the subcommittee, the Departments of Social Services and Housing and Community Development, and the Attorney General's Office, it became apparent that legislation would be required to effect such reallocation. The subcommittee's proposal, endorsed by the full Commission and enacted by the 1996 General Assembly and approved by the Governor in House Bill 675 requires reallocation of at least 7.5 percent of the fuel assistance block grant to weatherization assistance programs.

**Interstate ozone agreements.**

The Energy Preparedness Subcommittee was also directed to review a legislative proposal promoted by the Virginia Center for Energy and Economic Development (CEED), a nonprofit organization dedicated to promoting coal as an energy source. CEED asked the Commission to endorse legislation conditioning Virginia's participation in any interstate ozone agreement upon General Assembly review following a study of any such proposal's economic and environmental impact.

CEED's proposal was prompted by recent activity by the Ozone Transport Assessment Group (OTAG), an EPA-coordinated organization of state environmental protection agencies. The premise of OTAG is that some states required to meet mandatory Clean Air Act emissions standards for ozone are unable to do so because of neighboring states' emissions. These emissions are said to be transported interstate by wind patterns into the nonattainment areas. OTAG member states with nonattainment areas hope to obtain cooperative agreements with neighboring states to voluntarily reduce their ozone-producing emissions.

The Energy Preparedness Subcommittee received testimony from OTAG and CEED representatives on the issue. An OTAG representative advised the subcommittee that he found CEED's proposal unobjectionable, in principle. He noted, however, that the timing of any prior legislative review would be critical. The subcommittee recommended and obtained Commission endorsement of proposed legislation incorporating key elements of the CEED proposal. The legislation was introduced as House Bill 1512, which was passed by the 1996 Session and signed by the Governor.

**Oil and gas.**

Virginia's natural gas industry is enjoying high levels of conventional and coal bed methane natural gas production. Natural gas industry representatives told the Commission that this industry should be better represented both on the Virginia Coal and Energy Commission and on the Coalfield Economic Development Authority (CEDA). The Oil and Gas Subcommittee endorsed and the Commission approved legislation (i) stipulating that the Commission's at-large appointees shall include natural gas representatives and (ii) adding to CEDA a representative named by the largest oil and gas producer. The General Assembly approved and the Governor signed both measures: Senate bills 285 and 286.

## II. COAL SUBCOMMITTEE

### A. THE COALFIELD EMPLOYMENT ENHANCEMENT TAX CREDIT; HJR 586

In 1994, the Coal Subcommittee examined the issue of reversing the current downward trend in Virginia coal production and employment. One result of this work was a bill enacted by the 1995 General Assembly (HB 2575, Acts of Assembly Chapter 775, *Appendix A*) which provided a tax credit for persons with an economic interest in coal mined in Virginia. The Commission recommended that the Coal Subcommittee continue its analysis of the Virginia coal industry's economic problems as part of its work in 1995. Accordingly, a study resolution was introduced in the 1995 General Assembly Session as House Joint Resolution 586 (*Appendix B*). The resolution requested the subcommittee to continue its study of ways, including tax credits, of reversing the downward trend in Virginia coal production and employment. In fashioning recommendations, the subcommittee was directed to consider the potential impacts on Virginia's existing coal producers and strive to ensure that no Virginia producers were given an unfair competitive advantage over other Virginia producers.

Pursuant to HJR 586, the subcommittee decided to explore possible improvements to Chapter 775's tax credit scheme, which was structured as follows. The amount of the credit was based on the thickness of the seam from which the coal was mined: 60 cents per ton of coal mined from a seam less than 33 inches thick, 50 cents per ton of coal mined from a seam 33 inches or larger, and 25 cents per ton of surface-mined coal. Under the legislation, taxpayers would begin to accrue the credit for tax years beginning on and after January 1, 1996, and would be able take the credit on their tax returns beginning January 1, 1999. Only one year of credits would be allowed annually. No credit could be taken unless general fund revenue in the fiscal year for which the credit was taken exceeded the official estimate of general fund revenue by at least the cost of the credits. The credits were to expire in 2001. The bill also created a tax credit of three dollars per ton of coal mined in Virginia purchased by steam producers, defined as persons who sell steam energy to a manufacturing company in the Commonwealth or who use steam to produce manufactured goods.

Throughout the interim, the subcommittee focused on four issues in determining whether Chapter 775 assists the coal industry in the best manner possible: (1) the amount of the tax credit authorized by the bill, (2) the lag time between the earning and the application of the tax credit, (3) the allocation of tax credits between the two categories of seam thicknesses, and (4) the contingency of the tax credit on general fund revenue exceeding the official estimate by at least the cost of the credits.

### Contingency; lag time

The subcommittee agreed that the requirement of the new law that would prohibit the taking of the tax credit unless general fund revenue exceeds official estimates should be eliminated. Otherwise, the bill's goal of encouraging coal companies to invest in new mines and new workers will not be served, because companies will not be able to plan on receiving the tax credit. The subcommittee also agreed to propose eliminating the provision of the law that delays application of the tax credit several years after the credit is earned.

### Amount of the tax credit

The subcommittee also agreed that a larger tax credit than that authorized by Chapter 775 of 1995 would better assist the coal industry. In order to determine the appropriate credit amount, the subcommittee analyzed the revenue impact of the credit provided by Chapter 775 and the fiscal effect that a larger credit might have on the Commonwealth.

Tim Winks, assistant tax commissioner, testified before the subcommittee. He told the subcommittee that the revenue impact of the Chapter 775 was expected to be $17.6-19.7 million per year, starting in fiscal year 1999. (This amount was later projected by the Center for Public Service and Virginia Center for Coal and Energy Research to be $15 million. The reduction of the estimate to was due to the loss of coal production from the recent closing of Westmoreland Coal Company's

Virginia operation.) Also, there would be a fiscal impact in 1997 and 1998 of about $1.5 million due to the extension of the cogeneration tax credit and the new consumption tax credit for steam producers. He noted that bill prohibited more than one credit being taken on a particular ton of coal, which could lead to negotiation between producers and consumers of coal as to who will claim the credit.

Dr. Carl Zipper, associate director of the Virginia Center for Coal and Energy Research (VCCER), presented an estimate of the annual net cost to the Commonwealth of a tax credit which would provide $55 million per year to the coal industry. This amount was analyzed because the Virginia Coal Association has determined that $55 million is the approximate amount of tax relief necessary to sustain coal production and employment at 1994 levels until 2005. The tax credit as authorized in Chapter 775 would have provided $16-18 million in credits. House Bill 2575 as originally introduced would have provided approximately $55 million in tax credits.

Dr. Zipper explained that two major factors would partially offset the gross cost of a $55 million tax credit to the state treasury. First, without the credit, decreasing coal production would result in a loss of tax revenue to the state because fewer taxes would be paid by coal producers, their employees and supporting industries. VCCER research indicates that for each dollar of loss in coal sales suffered by producers, state and local tax revenues decline by approximately $0.105. The second factor: a declining coal industry will cause the state to incur social costs such as unemployment compensation and welfare payments.

A recent VCCER study estimated that for each million tons of coal production decline, 700 southwestern Virginia jobs are lost. However, it appears that the avoided social costs factor would have only minimal effect on the net cost of the tax credit compared to the avoided tax revenue loss factor. Dr. Zipper's analysis concluded that the net cost would be $28 million less than the gross cost in the year 2000, and $34 million less than the gross cost in the year 2005 (*Appendix C*). The analysis relied on a forecast prepared by a consultant for the Virginia Coal Association addressing the effect of a $55 million tax credit on coal production.

Dr. Zipper also briefed the subcommittee on the study that the VCCER had contracted to perform for the Virginia Port Authority. The Port Authority was required by Chapter 775 to report on the effect the coal production tax credit "has or will have on the export coal businesses at the Ports of Hampton Roads." The plan for the study was first to estimate the amount in tax credits that would be applied to mines producing export coal that is shipped through the port, and then estimate the effect the credits would have on coal sales prices. Two parallel approaches, an econometric approach and an empirical approach, were used in an attempt to project how the credits will influence coal production and its economic impacts.

Both approaches were necessary because the relationship between price and production is complex. Dr. Zipper's presentation emphasized the difficulty of fully accounting for all factors relevant to the relationship between tax credits and sales of coal within the time frame scheduled for the study (*Appendix D*).

As part of the study, Dr. Zipper and his colleagues assessed the effect the projected change in export tonnage would have on the businesses at the port and also estimated statewide economic impacts of the credit. The analysis did not take into account the provision of Chapter 775 that made the availability of the tax credit contingent upon general fund revenue exceeding official estimates. The subcommittee requested that the VCCER expand its study to assess the fiscal impacts not only of the tax credit in its present amount, but also the effects of the tax credit in twice and three times its present amount.

When the study was complete, Dr. Zipper returned to explain the results. The study predicted that the tax credit level authorized by Chapter 775 was unlikely to stimulate coal production in Virginia by more than one million tons per year. If, however, the credit amounts of 25 cents per ton of surface coal and 50-60 cents per ton of underground coal were doubled, coal production could increase by between one and five million tons per year through 2005. A tripled tax credit could increase production by between one and six million tons per year (*Appendix E*). It should be noted that these are increases above projected production levels without the credit; because of declining coal reserves, overall production of coal will continue to decline.

Increased production resulting from a doubled tax credit could prevent the loss of up to 5000 jobs between now and the year 2004. The credit in its present amount is unlikely to save more than 1000 jobs in that time period. A Weldon Cooper Center for Public Service study corroborated these findings indicating that the doubled credit should stabilize coal-related employment for several years. Rising unemployment would likely have a greater social impact in the coalfields than in other parts of the state because fewer of that region's women are members of the labor force (House Document No. 7, 1996).

The VCCER study also compared state and local revenues generated by enhanced coal production and employment with the gross outlay from the state treasury required to pay for the credit. The doubled tax is expected to result in revenues equaling 20 to 70 percent of the cost of the credit per year until 2005. Based on the information provided by the VCCER and Center for Public Service, the subcommittee agreed to propose that the coal production tax credit be doubled in amount, from a total amount of approximately $15 million to approximately $30 million.

### Seam thickness

Dr. Zipper also described to the subcommittee the influence of seam thickness on mining costs. As mine height decreases, labor productivity declines, while non-labor costs and materials handling costs increase. According to several operators, consultants and Bureau of Mines personnel, 38-42 inches is typically the minimum vertical space within which mine equipment can operate in Virginia. Attempts to recover coal from thinner seams require the mining of rock along with the coal. Consequently, more mine area must be serviced for each ton of coal produced, and rock must be transported from the mine and managed as solid waste. Dr. Zipper presented an analysis showing how cost per ton increases as mine thickness decreases. Assuming 38 inches minimum vertical mine space, the analysis showed that the rate of cost increase per decreasing inch of thickness begins to grow significantly at 38 inches of seam height (*Appendix* F). Dr. Zipper cautioned, however, that actual mining costs vary widely according to mine conditions and that the cost figures used in his analysis are not necessarily average or typical.

W. Thomas Hudson, Virginia Coal Association President and subcommittee member, noted that disagreement exists within the coal industry as to whether the seam thickness delineations in Chapter 775 should be changed. Therefore, the Virginia Coal Association decided not to take a position on the issue. Several coal company representatives, however, presented their views on the subject to the subcommittee.

Ken Price of Amvest Corporation agreed with Dr. Zipper's statement that many variables affect the cost of coal mining, but he added that a great deal of the coal left in Virginia is in small blocks of thin-seamed coal, and that he has observed mining operations whose mining costs have increased dramatically when they began to mine thinner seams. He told the subcommittee that mine height is important, and that providing an increased tax credit for coal from thin seams would help the small operators who mine smaller reserves. This would have a significant positive impact on employment, according to Price, because many jobs can be generated by smaller operators if they are able to mine thin seams. Stuart Smith of Amvest Corporation agreed that the emphasis of the coal production tax credit should be on thin seams. While many factors influence mining profitability, coal companies are apparently unlikely to reconsider decisions to forego mining a thin seam.

Chip Barker, corporate counsel with Rapoca Energy Company, told the Commission that most of the company's reserves in Buchanan and Dickinson Counties exist in seams thinner than 36 inches. According to Barker, a tax credit in the range of $1.20-$1.50 per ton would ensure that existing thin-seamed mines could continue to operate for several years. A tax credit in the range of $1.80-$2.00

per ton might allow companies to open new mines and maintain or increase current production and employment levels. Richard Waddell, manager of Health, Safety and Environment at Jewell Smokeless Coal Corporation, said that his company experienced a 25 percent drop in production last year due to low prices and high mining expenses associated with thin seams. Almost all of the company's identified coal reserves are in seams of less than 36 inches, and one third of that amount is in seams of less than 30 inches. Waddell said that a tax credit of three to four dollars per ton of coal mined from 30-inch or smaller seams would allow companies to mine thin seams and to avert the dilemma of whether to invest further capital in a mine (e.g., replacing old equipment) or close it.

John Brian of the Pittston Company countered that thick seams can be more expensive to mine than thin seams. Pittston compared mining costs for seven of its mines and found, with one exception, that the thicker seams were more expensive to mine. One of Pittston's 60-inch seams cost seven dollars per ton more to mine than one of its 37-inch seams. Brian suggested that the bulk of the tax credits should be allotted to seams that are likely to be mined. A tax credit for seams in the 37 to 60 inch range would the best way to maintain or increase mining jobs in the short term. A credit for thin seams may be appropriate when thicker seams are no longer available, he said. Willard Owens of the United Company agreed that two seams of the same thickness may have very different mining costs. He encouraged the subcommittee to continue to study the issue of how best to maintain coalfield employment and to help the coal industry. Stephen G. Young sent a letter to the subcommittee expressing the views of his company, CONSOL, Inc. (*Appendix G*). He noted that seam thickness was merely one of several key factors that determined mining costs. Others include rock pressures, methane volumes, faults and floor and roof rolls. He urged the Commission to stand by the seam thickness allocation in the 1995 tax credit bill.

Several speakers and members of the subcommittee noted that allocating tax credits among seam thicknesses to promote employment is problematic. Geologic information on the seam thicknesses of Virginia's various coal reserves exists as a result of a mapping effort undertaken by the Department of Mineral Resources in the 1980s. It is possible to correlate this information with mine employment data to compare employment at thin seam mines with employment at thick seam mines. Because this effort would be extremely time-consuming and would involve proprietary information, however, a clear picture of the relationship between seam thickness and employment is unlikely to be available in the near future. Members of the subcommittee emphasized that the object of the tax credit is to maintain or increase Virginia coal mining employment in general, not to help particular Virginia coal companies to compete with other Virginia coal companies.

### Legislation

As a result of the subcommittee's work, SB 539 (*Appendix H*) was introduced by Senator Reasor in the 1996 Session of the General Assembly. The bill contained the provisions that the subcommittee had agreed upon. It eliminated language which (i) rendered the availability of the credit contingent on general fund revenue exceeding the official estimate, (ii) prohibited the taking of the tax credit before the year 1999, and (iii) limited the amount of credit which could be taken to one year of credits annually after 1999. The bill also increased the tax credit by allowing a $2.00 credit per ton of coal mined from a seam 36 inches or smaller, $1.00 for a seam larger than 36 inches, and 40 cents per ton of surface-mined coal. Each of these provisions was endorsed by the full Coal and Energy Commission, with the exception of the specific allocation of the tax credit among seam thicknesses. (The full Commission was unable to meet in time to discuss this element of the tax credit package but had endorsed the doubling of the credit in general). SB 539 failed, but a similar bill, HB 1454 (*Appendix I*), passed.

### Other studies

In addition to the Coal Subcommittee's study, the 1995 General Assembly directed that two other studies of the coalfield employment enhancement tax credit be undertaken. (These were contained in the third and fourth enactment clauses of Chapter 775.) The Virginia Port Authority was directed to study the tax credits' effects on the export coal businesses at the Ports of Hampton Roads. The Center for Public Service (in cooperation with the Virginia Port Authority, Department of Taxation, Department of Mines, Minerals and Energy, Department of Economic Development and Office of the Attorney General) was directed to consider the policy, legal and economic impacts and efficiency of the tax credit. The subcommittee maintained communication with Katherine D. O'Neal, deputy director for administration of the Virginia Port Authority, and Simeon Ewing, director of the Southwest Virginia Office of the Cooper Center for Public Service, throughout the interim to avoid duplication among the three studies and facilitate the exchange of information. The Center for Public Service report is available as House Document No. 7 (1996).

## B. OTHER COAL ISSUES

### Financing a coke-making plant in southwest Virginia

Dr. Richard A. Wolfe, a member of the subcommittee, pointed out that one way to increase coal production in Virginia is to develop new ways to use coal. He described to the subcommittee a technology that he has developed that can make coke that is worth $150 a ton from coal that costs $25 per ton. The United States is currently importing 3.5 million of the 26 million tons of coke used in this country per year. A plant using Dr. Wolfe's technology and processing 70,000 tons of coal to produce 60,000 tons of coke a year was estimated to cost approximately $12 million to build.

Citing the economic development benefits such a plant would provide for Southwest Virginia, Dr. Wolfe sketched out a public/private funding proposal for the plant. If six million dollars could be raised in the public sector, the private capital market would likely finance the remainder. One method of raising the necessary public funding would be levying a one cent per gallon tax on gasoline in the Ninth Congressional District. Such a tax, he projected, would probably raise $5.4 million in one year. Staff was asked to obtain information about prior legislation authorizing a similar gas tax in Northern Virginia to help fund mass transit projects. The resulting staff memorandum is attached as *Appendix J*.

## III. ENERGY PREPAREDNESS SUBCOMMITTEE

### A. FUEL AND WEATHERIZATION ASSISTANCE

Each year, the Energy Preparedness Subcommittee receives reports concerning programs providing home heating fuel and weatherization assistance to low income individuals and families. As a part of its 1995 activities, the subcommittee examined provisions in federal law permitting the allocation of federal fuel assistance funds to home weatherization programs. Legislation requiring such reallocations was recommended to and endorsed by the full Commission.

The Low Income Home Energy Assistance Program (LIHEAP) is a federally funded, state-administered program providing short-term home heating fuel assistance to qualifying low-income individuals and families with annual incomes under $8,000. LIHEAP is administered in Virginia by the Department of Social Services. During program year 1994-1995, the Department paid out more than $21 million in LIHEAP benefits. The average benefit paid per household was $181 (*Appendix K*).

The Weatherization Assistance Program (WAP), administered by the Department of Housing and Community Development, is principally funded by grants from the U.S. Department of Energy. WAP is designed to reduce the energy costs of low-income households by weatherizing homes and providing essential repairs to heating systems. Its statewide budget in 1994-1995 was $4.7 million. A budget of $3.5 million was projected for 1995-1996 (*Appendix L*).

When the subcommittee met in 1994, several of its members suggested that WAP and LIHEAP should be better coordinated. They noted that individuals and families receiving fuel assistance benefits should have weatherized homes and heating systems in good repair. This would help reduce each home's heating costs while freeing fuel assistance dollars for other eligible program participants. Some collaboration has occurred in LIHEAP's crisis assistance component as LIHEAP has paid WAP weatherization subcontractors to perform emergency heating equipment repairs.

The issue of program coordination was addressed directly in the subcommittee's June 12 meeting. The subcommittee learned that federal law permits up to 15 percent of LIHEAP funding to be used for home weatherization. An additional 10 percent may be allocated to weatherization upon application to and approval by the program's federal administrators.

Cathy Olivis from the Department of Social Services (DSS) told the subcommittee that in DSS's view, LIHEAP's primary purpose is helping qualifying low-income families pay their current heating bills. The WAP program has a different objective: weatherizing the homes of low-income families and recouping the cost through energy savings realized over time. Olivis said that WAP reallocations would substantially reduce LIHEAP's capacity to serve its primary function. She noted that if 15 percent of the anticipated 1995 fiscal year grant was allocated to weatherization, LIHEAP benefits would be reduced by approximately 42 percent, or from an average annual grant of $181 per household to $75.

Olivis also pointed out potential regulatory problems in allocating LIHEAP funding to weatherization. Monitoring procedures would be needed to ensure that funds allocated to WAP are used in accordance with the regulations issued by the U.S. Department of Health and Human Services. Since WAP is under the U.S. Department of Energy, WAP and LIHEAP are operating under different sets of federal statutes and regulations.

Proponents of the weatherization program strongly advocated allocating LIHEAP funding to weatherization. William Beachy from the Department of Housing and Community Development told the subcommittee that a large number of WAP-eligible households go unserved each year because of WAP's declining funding--due largely to the depletion of oil-overcharge moneys that once provided a substantial part of the program's funding. According to Beachy, a 15 percent LIHEAP allocation would nearly double the number of households weatherized each year.

The subcommittee asked the Department of Social Services and the Department of Housing and Community Development to develop a plan allocating LIHEAP funding to weatherization. In July, the DSS board approved an allocation of approximately 8 percent ($1.4 million) of LIHEAP's expected federal grant of $18 million to WAP. However, the allocation was not completed. DSS concluded that state LIHEAP regulations required amendment via the Administrative Process Act (APA) before any such reallocation could be made.

At the direction of the full Commission, Delegate James Almand, the subcommittee's chairman, requested in September a formal opinion from the Attorney General concerning the Administrative Process Act issue. A copy of the request is attached as *Appendix M.* The primary question submitted to the Attorney General was whether reallocating LIHEAP funding to WAP pursuant to federal statute required prior amendment to DSS' LIHEAP program regulations. The Attorney General's response, received in January 1996, is attached as *Appendix N.* The Attorney General wrote that amendments to the DSS regulations would require compliance with the APA. He left unanswered, however, the question of whether reallocation of LIHEAP federal block grant money to WAP pursuant to federal statutory authorization required any preliminary state regulatory action.

At its final meeting in December, the subcommittee learned that although LIHEAP funding had been approved for emergency home heating system repairs in conjunction with "crisis assistance," no money had been allocated to WAP for basic home weatherization in 1995-1996. The subcommittee voted to recommend legislation requiring DSS to allocate at least 7.5 percent of the LIHEAP federal block grant to WAP to the extent permitted by federal law. This unanimous subcommittee recommendation was presented to and approved by the Commission at its January 9 meeting. (A copy of the legislative proposal as enacted by the 1996 General Assembly and approved by the Governor is attached as *Appendix O*).

## B. OZONE TRANSPORT ASSESSMENT GROUP (OTAG)

Virginia Center for Energy and Economic Development (CEED) representatives appeared before the Commission at its August meeting in Blacksburg to furnish a briefing on developments related to ozone-producing emissions. CEED is a national, nonprofit organization dedicated to promoting the benefits of coal. CEED representatives told the Commission that the U.S. Environmental Protection Agency (EPA) is coordinating the formulation of an interstate ozone reduction agreement whose emissions reduction standards are likely to exceed the stringency of those imposed by the Clean Air Act. The mechanism for developing this interstate agreement is the Ozone Transport Assessment Group (OTAG). According to CEED, OTAG is developing air emissions controls that may exceed those required by the Clean Air Act (*Appendix P*).

OTAG is similar to the Northeast Ozone Transport Commission (OTC) which was created by the 1990 federal Clean Air Act Amendments. The OTC, consisting of 12 Northeastern states, was created by Congress and directed to seek means of reducing urban ozone. The Clean Air Act, as amended in 1990, establishes air quality standards. States with areas failing to comply with these standards are subject to stringent pollution control measures, such as enhanced motor vehicle emissions inspections as well as emissions offset requirements for industry. The 1990 amendments also require utilities to reduce nitrogen oxide (NOx) emissions. These emissions must be controlled through the use of "reasonably available control technology" (RACT).

CEED representatives suggested that these critical ozone issues are being reviewed by OTAG under threat of litigation by the EPA pursuant to Sections 110 and 126 of the federal Clean Air Act. The Commission was advised that OTAG's objective is agreements with 32 states (including Virginia) establishing NOx emissions standards that will likely exceed the emissions control standards imposed by the 1990 Clean Air Act Amendments, and will probably cost utilities and others billions of dollars over and above compliance costs associated with the 1990 amendments.

CEED's spokesman, Eugene Trisko, told the Commission that the emissions reduction measures under consideration by OTAG are based on questionable scientific assumptions and data. CEED contends that these measures, including mandates for further reducing stationary source (e.g., power plants) emissions, will reduce ozone only slightly while imposing staggering costs on business and industry. The Commission voted to express its concern about these possibilities to the Virginia Congressional Delegation via letters from the Commission's chairman (*Appendix Q*). Responses received by the Commission are attached as *Appendix R*.

CEED also asked the Commission to support legislation conditioning Virginia's participation in any interstate ozone agreement on General Assembly review and approval, following a study by designated state agencies of the environmental and economic impact of any such agreement (*Appendix S*). This legislative proposal was assigned to the Energy Preparedness Subcommittee for its review and recommendations. The Subcommittee invited representatives from OTAG, CEED, and Virginia's Department of Environmental Quality (DEQ) to present their views on the proposal.

**OTAG's perspective**

Bharat Mathur, chief of the Illinois Environmental Protection Agency's Bureau of Air, appeared before the subcommittee on behalf of OTAG. Mathur is an assistant to Illinois EPA Commissioner Mary Gade, who chairs the OTAG Policy Decision Group composed of OTAG member states' environmental commissioners and two U.S. EPA directors. Mathur, who heads that group's advisory panel, summarized OTAG's background and purpose for the subcommittee. The federal Clean Air Act, he said, designated various regions throughout the U.S. as "nonattainment areas" for ozone. The 1990 Amendments required states with these areas to submit attainment demonstrations by November 1994. A 1995 EPA memo provided to the subcommittee showed that for many states--perhaps most--meeting this deadline was not feasible (*Appendix T*).

According to Mathur, the states' nonattainment difficulties resulted largely from complex upwind and downwind flows of ozone and ozone precursors (nitrous oxide and volatile organic compounds). These wind patterns are critical to nonattainment areas whose ozone problems may be caused, in some part, by emissions transported into nonattainment areas from remote emissions sites. This phenomenon is known as "ozone transport." Mathur furnished diagrams of air flow movements showing that some of Chicago's ozone problems, for example, may be directly linked to airborne transport of emissions originating in states along the East Coast (*Appendix U*).

To help states with nonattainment areas address the transport issue, the EPA approved the formation of OTAG to study interstate ozone movement. The EPA took this action as an alternative to imposing sanctions on those states currently unable to demonstrate ozone-reduction attainment. OTAG will coordinate a two-year process (beginning in 1995 and ending in 1996) in which states and the EPA will assess and refine regional emissions control strategies focusing on ozone transport.

OTAG is using computer modeling to study the causes and consequences of ozone transport. The results will be used to develop a consensus plan (agreed to by OTAG member states and the EPA) for additional emissions reductions on local, regional and national levels. The consensus envisioned by the EPA will require agreements between OTAG states--some of them without nonattainment areas--and the EPA to implement emissions-reduction programs that will be in addition to those required by the Clean Air Act. Thus, under such agreements, non-OTC states contributing to ozone problems via ozone transport into nonattainment areas would voluntarily reduce their emissions to help states with nonattainment areas satisfy their ozone-reduction obligations under the Clean Air Act.

If, however, this state-EPA consensus cannot be achieved by the end of 1997, the EPA intends to use its authority under the Clean Air Act to ensure that the reductions established by the Act are met. As authorized by §§ 110 and 126 of the Act, this enforcement authority includes EPA suits against states failing to demonstrate ozone-reduction attainment. Those states, in turn, can sue states whose emissions are contributing to nonattainment via ozone transport.

Mathur stated that the OTAG end product will be a recommendation to the EPA addressing ozone transport, and that OTAG's leadership has no preconceived notion of what that recommendation will be. Currently, one OTAG work group is compiling state emissions inventories for the year 1990 and anticipated emissions inventories for future years. Another work group will use these inventories, along with information about meteorological conditions during peak ozone episodes in 1988, 1991, 1993 and 1995 to model the effect that various emissions controls might have on ambient ozone concentrations. Another work group is examining the potential for a nitrous oxide allowance trading program--similar to the sulfur dioxide program authorized by the 1990 Amendments.

Turning to CEED's legislative proposal, Mathur agreed that state legislative review of proposed emissions agreements should occur. However, Mathur noted, the timing of such a review is critical. Responding to CEED's criticisms of the scientific assumptions underlying OTAG's modeling process and potential emissions control measures, Mathur asserted that OTAG's use of available emissions and related data in the modeling process is scientifically sound.

**CEED response**

CEED representative Eugene Trisko, told the subcommittee that the annual cost of the emissions controls currently under consideration by OTAG is likely to exceed $5 billion in direct costs to utilities. Trisko challenged OTAG's utilization of 1988 ozone measurement data in its modeling. Graphs furnished by Trisko (*Appendix V*) showed that days above the 120 parts-per-billion threshold (the federal ozone standard for nonattainment) along the East Coast in 1993-1995 were less than half those indicated in 1988 (20 versus 40+). This, Trisko stated, demonstrates that the continuing implementation of the Clean Air Act is having a significant impact in reducing ozone. Moreover, EPA's computer modeling, to date, suggests that the controls under consideration would reduce ozone in the Northeast by only six to nine parts per billion a few days each year.

CEED reemphasized the basis for its legislative proposal. Such legislation, Trisko said, would ensure a thorough study of the economic impacts of interstate ozone agreements before state environmental protection agencies (such as Virginia's DEQ) are authorized to sign on. These studies should, he emphasized, focus on employment impacts, economic development, potentially higher utility rates, statewide business competitiveness, and potential risks of "stranded" utility assets.

**Department of Environmental Quality (DEQ) comments on OTAG**

DEQ representative Mike McKenna told the subcommittee that DEQ does not view Virginia's participation in OTAG as entirely voluntary. He characterized the OTAG process as "coercive," and questioned the wisdom of the OTAG leadership structure that, to date, includes no state legislators. Furthermore, he challenged the practical use of the EPA's ozone measurement methodology. The 120 parts-per-billion (ppb) ozone nonattainment threshold, McKenna said, is tied to a one-hour average. Since long-term ozone exposure creates the greatest health risk, the average should be computed over a larger number of hours to obtain a more meaningful assessment. According to McKenna, DEQ would like to see more cost-benefit analyses as part of the OTAG process.

The subcommittee reviewed a legislative draft incorporating components of the CEED proposal. The draft requires the Departments of Economic Development and Environmental Quality to study the impact of any proposed interstate ozone transfer agreement on the Commonwealth's economy, including, but not limited to, impacts on economic development and industrial competitiveness. Such a study would be conducted in conjunction with the General Assembly's review of any proposed interstate ozone transport agreement. The draft approved by the Subcommittee and ultimately by the full Commission on January 9 was enacted by the 1996 General Assembly and approved by the Governor as HB 1512 (*Appendix W*).

## IV. OIL AND GAS ISSUES

The Oil and Gas Subcommittee met to discuss issues affecting natural gas exploration and production in Virginia. B. Thomas Fulmer, director of the Department of Mines, Minerals and Energy's (DMME) Division of Gas and Oil, told the subcommittee that the number of permits issued in 1994 was 49 percent below the number issued in 1992, and the number of permit applications is expected to decreased further in 1995 (*Appendix X*). While the number of wells is decreasing, however, production of natural gas continues to increase: 37 billion cubic feet (BCF) was produced in 1993, and 50.2 BCF was produced in 1994 (*Appendix Y*). In 1994, over 51 percent of the gas produced in Virginia came from Buchanan County; Dickinson and Wise Counties followed with 28 percent and 18 percent, respectively (*Appendix Z*).

The increase in production is due largely to an increase in coalbed methane production. In 1989, 0.2 BCF of coalbed methane was produced in Virginia. In 1993, the first year in which more coalbed methane was produced than conventional gas, the amount was 19.9 BCF. In 1994, 28.3 BCF of coalbed methane was produced. Of the 93 natural gas wells that were drilled in the first three quarters of 1995, 86 are coalbed methane wells. In 1994, coalbed methane accounted for 56.4 percent of Virginia's natural gas production (*Appendix AA*). DMME expects production of coalbed methane to continue to increase. Because the first coalbed methane well in Virginia was drilled in 1988, the life expectancy for such wells has not been ascertained. While conventional wells have a life of about 40 years, coalbed methane wells may last for only 15 years.

Richard A. Counts of Commonwealth Energy Company discussed coalbed methane development in the Richmond basin, much of which lies in Chesterfield County. Coal was mined in this Triassic basin from 1748 until 1927. A paper published in February 1995 by DMME's Division of Mineral Resources cites an estimate that 0.3 to 0.9 trillion cubic feet of methane are present in the basin. Counts noted that this DMME publication and others providing data on estimated reserves have been very useful to companies considering new gas development projects. Significant natural gas production and use in the Richmond metropolitan area could contribute to attainment of air quality standards in the region. A ready supply of natural gas is also a factor that could attract new industry to the region because the supply is unlikely to be interrupted. Operations are expected to commence in the Richmond basin in September.

A. George Mason, president of the Virginia Oil and Gas Association (VOGA), told the subcommittee that the Virginia Center for Coal and Energy Research would soon be completing a study of the economic impact of the natural gas industry on Virginia. Recent events of importance to the industry include the selection of natural gas as the fuel for Red Onion Mountain prison being built in Wise County. Another is an economic development initiative occurring in Dickinson County, in which the industry is supplying free gas to companies that locate in a new industrial park.

In 1995, the General Assembly enacted two measures affecting the oil and gas industry. One designated DMME as the agency responsible for certifying whether equipment used in coal, oil and gas production is pollution control equipment under Va. Code § 58.1-3660. (This section allows local governments to exempt certified pollution control equipment from local taxation.) The second bill addressed circumstances in which coalbed methane development is planned but the operator of the affected coal cannot be found. The legislation allows a pooling order containing a finding that the coalbed methane operator has exercised due diligence in attempting to locate the coal operator to satisfy the requirement of the coal operator's signed consent.

DMME is reviewing its regulations pursuant to Governor Allen's executive orders directing agencies to determine whether their regulations cause Virginia industries to be at a competitive disadvantage compared to those in other states. Mason told the subcommittee that DMME met with representatives of the oil, gas and coal industries and that consensus on the regulations needing revision has been reached. He said that obtaining permits and keeping them current is more expensive to do in Virginia than Kentucky or West Virginia because Virginia requires more paperwork. Presently, it is not economically feasible for companies to drill new natural gas wells in Virginia because of (1) the regulatory cost and (2) low gas prices. He expressed concern that any reduction in the regulatory burden on the oil and gas industry that might occur may not happen until late next year.

The subcommittee met in early January 1996 to discuss legislative proposals offered by the Virginia Oil and Gas Association. Most of these were amendments to the Gas and Oil Act that would address some of the concerns raised by the industry at the subcommittee's earlier meeting (*Appendix BB*). The subcommittee endorsed proposals to add a representative of the natural gas industry to the Coal and Energy Commission and to add to the Coalfield Economic Development Authority a representative named by the largest oil and gas producer. The full Commission also endorsed these two proposals, with the modification that the number of members of the Commission would not change. The resulting legislation appears as *Appendices CC and DD*. Several of VOGA's other proposals were introduced as SB 476, which passed (*Appendix EE*).

Respectfully submitted,

Frank W. Nolen, Chairman
J. Paul Councill, Jr., Vice Chairman
Charles J. Colgan
H. Russell Potts, Jr.
Jackson E. Reasor, Jr.
William C. Wampler, Jr.
Watkins M. Abbitt, Jr.
James F. Almand
George W. Grayson
Harry J. Parrish
Jackie T. Stump
A. Victor Thomas
John Watkins
H. Kim Anderson
Donald B. Baker
Ronald J. Des Roches
Laura Bateman Hehner
W. Thomas Hudson
Lloyd Robinette
Richard A. Wolfe, Ph.D.

HB2575 Coal industry tax credits.

CHAPTER 775

An Act to amend the Code of Virginia by adding in Article 13 of Chapter 3 of Title 58.1 sections numbered 58.1-439.1 and 58.1-439.2 and to amend and reenact the third enactment of Chapter 730 of the 1988 Acts of Assembly, relating to coal industry tax credits.

[H 2575]

Approved April 6, 1995

Be it enacted by the General Assembly of Virginia:
1. That the Code of Virginia is amended by adding in Article 13 of Chapter 3 of Title 58.1 sections numbered 58.1-439.1 and 58.1-439.2 as follows:

§ 58.1-439.1. Coalfield employment enhancement tax credit.

A. For tax years beginning on and after January 1, 1996, but before January 1, 2001, any person who has an economic interest in coal mined in the Commonwealth shall be allowed a credit against the tax imposed by § 58.1-400 and any other tax imposed by the Commonwealth in accordance with the following:

1. For coal mined by underground methods, the credit amount shall be based on the seam thickness as follows:

| Seam Thickness | Credit per Ton |
|---|---|
| Under 33" | $.60 |
| 33" and Above | $.30 |

The seam thickness shall be based on the weighted average isopach mapping of actual coal thickness by mine as certified by a professional engineer. Copies of such certification shall be maintained by the person qualifying for the credit under this section for a period of three years after the credit is applied for and received and shall be available for inspection by the Department of Taxation. The Department of Mines, Minerals and Energy is hereby authorized to audit all information upon which the isopach mapping is based.

2. For coal mined by surface mining methods, a credit in the amount of twenty-five cents per ton for coal sold in 1996, and each year thereafter.

B. In addition to the credit allowed in subsection A, for tax years beginning on and after January 1, 1996, any person who is a producer of coalbed methane shall be allowed a credit in the amount of one cent per million BTUs of coalbed methane produced in the Commonwealth against the tax imposed by § 58.1-400 and any other tax imposed by the Commonwealth on such person.

C. For purposes of this section, economic interest is the same as the economic ownership interest required by § 611 of the Internal Revenue Code which was in effect on December 31, 1977. A party who only receives an arm's length royalty shall not be considered as having an economic interest in coal mined in the Commonwealth.

D. If the credit exceeds the person's state tax liability for the tax year, the excess may be redeemable by the Tax Commissioner on behalf of the Commonwealth for ninety-five percent of the face value within ninety days after filing the return. If the Commonwealth does not redeem such excess amount, it shall be transferable by sale.

E. No person may utilize more than one of the credits on a given ton of coal described in subsection A. No person may claim a credit pursuant to this section for any ton of coal for which a credit has been claimed under § 58.1-433 or § 58.1-2626.1. Persons who qualify for the credit may not apply such credit to their tax returns prior to January 1, 1999, and only one year of credits shall be allowed annually beginning in 1999. No credit authorized by subsections A and B shall be taken by any taxpayer in 1999 unless general fund revenue in fiscal year 1997-98 exceeds the official estimate of general fund revenue by at least the cost of the credits authorized by subsections A and B as estimated by the Department of Taxation. In each following year no credit shall be taken by any taxpayer unless general fund revenue in the fiscal year ending the prior June 30 exceeds the official estimate of general fund revenue by at least the cost of the credits authorized by subsections A and B.

§ 58.1-439.2. Qualifying steam producers tax credit.

For tax years beginning on and after January 1, 1996, but before January 1, 2001, a steam producer shall be allowed a credit against the tax imposed by § 58.1-400 in the amount of three dollars per ton for each ton of coal mined in Virginia purchased by such steam producer. "Steam producer" means a person who sells steam energy to a manufacturing company in the Commonwealth or uses steam to produce manufactured goods. In order to receive the credit under this section, the steam producer shall include a certification from the coal producer that the coal was mined in Virginia. In no event shall the credit allowed hereunder exceed the total amount of tax liability of such steam producer. Any tax credit not usable for the taxable year may be carried over to the extent usable for the next five succeeding tax years or until the full credit is used, whichever is sooner.

2. That the third enactment of Chapter 730 of the 1988 Acts of Assembly is amended and reenacted as follows:

3. That the provisions of this act shall expire on December 31, ~~1996~~ 2001.

3. That the Virginia Port Authority shall undertake a study of the effect the Coalfield Enhancement Tax Credit has or will have on the export coal businesses at the Ports of Hampton Roads, and make its report to the chairmen of the Senate Finance and House Finance Committees by December 1, 1995.

4. That the Center for Public Service, in cooperation with the Virginia Port Authority, Department of Taxation, Department of Mines, Minerals and Energy,

Department of Economic Development, the Office of the Attorney General, shall undertake a study of the policy, legal, and economic impacts of the credits authorized by §§ 58.1-433 and 58.1-2626.1 and to be authorized under this act, as well as the efficiancy of such credits, and make its report to the Governor and the chairmen of the Senate Finance and House Finance Committees by December 1, 1995.

LD6928460

# HOUSE JOINT RESOLUTION NO. 586

Offered January 23, 1995

*Requesting the Coal Subcommittee of the Virginia Coal and Energy Commission to continue its study of ways to reverse the downward trend in Virginia coal production and employment.*

---

Patrons—Stump, Johnson, Kidd, Kilgore and Phillips; Senators: Reasor and Wampler

---

Referred to Committee on Rules

---

WHEREAS, since 1990, the Virginia coal industry has suffered precipitous declines in coal production and employment; and

WHEREAS, this downward spiral is continuing, as evidenced by Virginia Employment Commission data showing that 1,603 unemployment claims were filed by Virginia coal industry employees during the first nine months of 1994; and

WHEREAS, a December 1994 report of the Virginia Center for Coal and Energy Research (VCCER) shows that Virginia's difficult geologic conditions are the primary reason for these declining production and employment figures; and

WHEREAS, according to VCCER's report, for every one million-ton decline in Virginia coal production, 876 jobs and $25.2 million in payroll will be lost; and $3.58 million in state and local tax revenue will be lost; and the Commonwealth will incur additional unemployment compensation and public assistance costs; and

WHEREAS, the demand for Virginia coal is expected to decline from 41.6 million tons in 1993 to 38.9 million tons in 1995, 32.9 million tons in 2000, and 31 million tons in 2005; and

WHEREAS, Southwest Virginia will be severely impacted by these declines, and significant negative effects will be felt throughout the Commonwealth; and

WHEREAS, the Coal Subcommittee of the Virginia Coal and Energy Commission examined many of the issues surrounding the decline of the Virginia coal industry during 1994, but because of the number and complexity of the issues the subcommittee requires additional time to study the matter; now, therefore, be it

RESOLVED by the Senate, the House of Delegates concurring, That the Coal Subcommittee of the Virginia Coal and Energy Commission be requested to continue its ongoing study of ways, including tax credits, of reversing the downward trend in Virginia coal production and employment. In fashioning recommendations, the Coal Subcommittee shall consider the potential impacts on Virginia's existing coal producers and strive to ensure that no Virginia producers are given an unfair competitive advantage over other Virginia producers.

The Division of Legislative Services and the staff of the Senate Finance and House Appropriation Committees shall provide staff support for the study. All agencies of the Commonwealth shall provide assistance to the Coal Subcommittee, upon request.

The Coal Subcommittee is requested to complete its work in time to submit its findings and recommendations to the Governor and the 1996 Session of the General Assembly as provided in the procedures of the Division of Legislative Automated Systems for the processing of legislative documents.

# State Fiscal Effects c^f Co: l Proc uction Tax Credit
# r \ rgin ia Coal Association

Presented to the Coal Subcommittee
of the Virginia Coal and Energy Commission
June 20, 1995. Roanoke

Carl E. Zipper
Virginia Center for Coal and Energy Research

This presentation provides a rough estimate of state fiscal effects of a production tax credit proposal advanced by Virginia Coal Association. The Association and its members maintain that approximately $55 million in production tax credits would allow the Virginia coal industry to maintain production at the 1994 level until the year 2005. Without that tax credit, the Association and its members maintain that production levels and mine employment will decline by approximately 25 percent over the next decade. The result will include severe economic consequences for southwestern Virginia's coal-producing counties. The information which follows has been prepared upon request by the Coal Subcommittee.

Basic Assumptions:

Coal production will decline to 29.5 million tons by the year 2005 unless a coal production tax is established. Per-ton production credit amounts would be based on seam thickness. The production tax credit would not be available to producers who ship to Virginia utilities claiming the $3.00 per ton utility tax credit. Coal producers would be eligible to receive tax credits in 1997 and subsequent years based on year-earlier production. The $55 million tax credit would not be indexed to inflation, *i.e.* its real-dollar value would decline with time. Labor productivity would remain constant. The real-dollar price of coal will increase by approximately 1 percent per year through the year 2000 and 0.15 percent per year between 2001 and 2005. The above assumptions are based on information provided by the Virginia Coal Association and Energy Ventures Analysis.

In conducting the analysis, we also assumed that consumption of coal by Virginia utilities will be unaffected by the production tax credit. The listed figures are estimates. Inflation is assumed to occur at a 3 percent annual rate. The gross cost of the production tax credit was calculated at $1.65 (1996 dollars) per eligible ton.

Gross vs. Net Costs of the Production Tax Credit.

The gross costs of the tax credit to the state treasury will be partially offset by two major factors. One is the fact the tax credit will avert losses of state and local tax payments supported by the coal industry, its employees and supporting industries, and transportation of coal through the state. VCCER research indicates for each dollar of coal sales revenues that is lost by the state's producers, state and local tax revenues decline by approximately $0.105. The analysis was conducted assuming a 6-month lag in coal-related tax payments.

The other offsetting factor is social costs. As coal-mining employment declines, economic opportunities in the coalfield counties are likely to become even more limited. There is a likelihood that many of those losing jobs as a result of declining coal production will be forced to accept unemployment compensation and/or welfare payments.

In order to estimate social costs, we were forced to make some assumptions. Our 1995 study estimates that 700 jobs in the southwestern Virginia coal-producing counties are lost for each million tons of coal production decline. Our assumption is that three-fourths of those losing jobs will accept unemployment benefits totaling $1800 per benefit claimant ($150 average weekly benefit, 12 weeks benefit duration).

According to the Virginia Employment Commission, 35 to 40 percent of southwestern Virginia's unemployment compensation claimants exhausted their benefits in 1994. It is unlikely that a person who loses employment would apply for welfare without first exhausting unemployment benefits. An analysis of figures provided by the Virginia Department of Social Services yields the following: an average household receiving Aid For Dependent Children (2.6 individuals) costs the state $8100 over a 2.5 year benefit period, while the average household receiving Medicaid (1 adult and 1.6 children) costs the state $7100 over a 2.35 year period. Many welfare families also receive Food Stamps, but this program places only a small financial burden on the state ($90 per year in administrative expenses). Figure 2 was constructed assuming that 10 percent of those losing jobs due to coal production declines, and their families, would receive welfare. The above figures indicate that, on average, a family on welfare costs the state approximately $15,000 over a 2.5 year period.

Analysis:

Figure 2 was constructed using the above assumptions. The figure indicates that the net cost of the production tax credit to the state treasury will decline as years pass and the credit takes effect. In evaluating Figure 2, note the following:

1. The tax credit legislation provides a net benefit to the state treasury in Year 1. This occurs because coal production increases immediately in anticipation of the tax credit, but the state treasury suffers no loss of tax revenues until the following year.

2. Given the assumptions of this analysis, the tax credit has an increasingly stimulative effect while decreasing in real-dollar magnitude with the passage of time. This effect would occur if the tax credit were to stimulate investment in developing new mine capacity.

3. The assumptions regarding the number of people who will draw welfare and/or unemployment compensation benefits as a result of tax credit non-implementation are unsubstantiated. These assumptions may not be correct. However, social costs have only a minimal effect on the analysis.

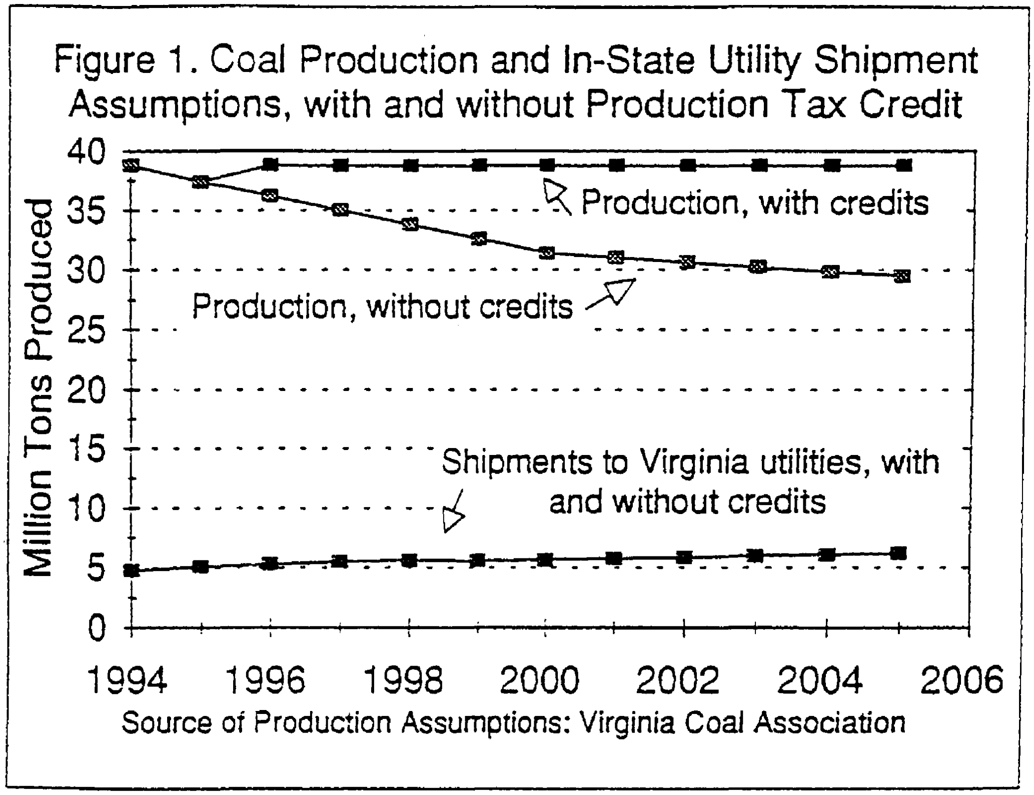


Figure 1. Coal Production and In-State Utility Shipment Assumptions, with and without Production Tax Credit
Million Tons Produced
Production, with credits
Production, without credits
Shipments to Virginia utilities, with and without credits
40
35
30
25
20
15
10
5
0
1994
1996
1998
2000
2002
2004
2006
Source of Production Assumptions: Virginia Coal Association

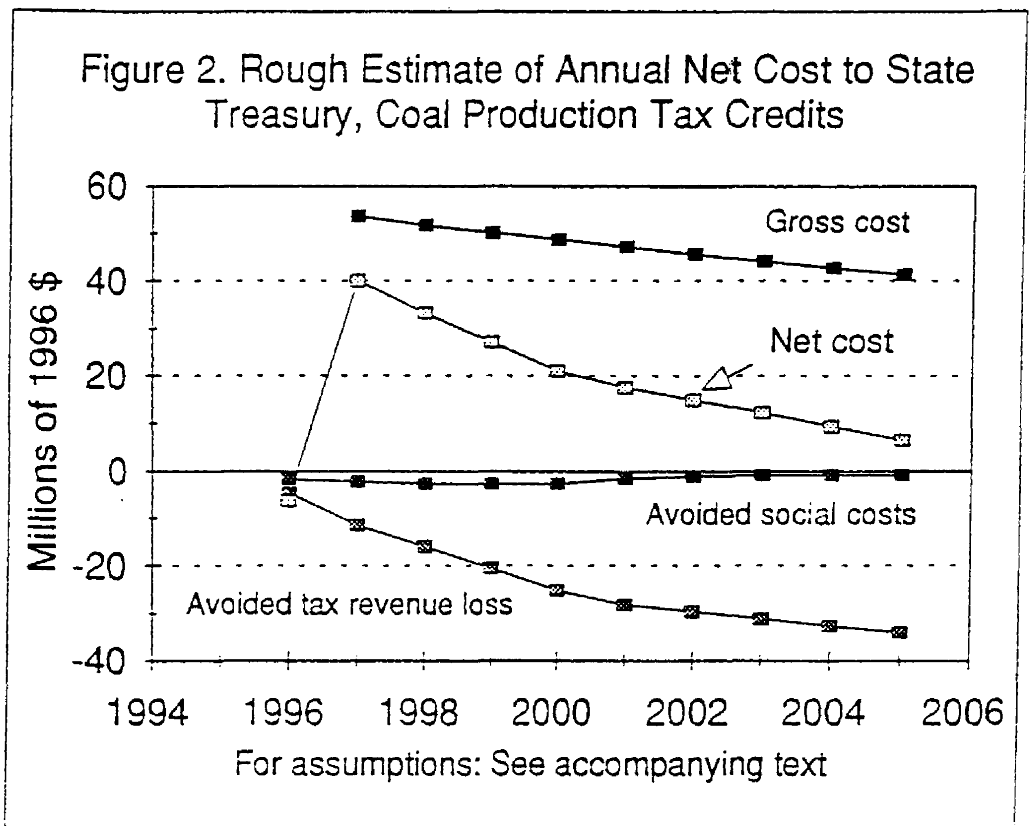


Figure 2. Rough Estimate of Annual Net Cost to State Treasury, Coal Production Tax Credits
Millions of 1996 $
Gross cost
Net cost
Avoided social costs
Avoided tax revenue loss
60
40
20
0
-20
-40
1994
1996
1998
2000
2002
2004
2006
For assumptions: See accompanying text

# House Bill 2575 Study Plan

Carl E. Zipper and S. Murthy Kambhampaty

Presented to the Coal Subcommittee of the Virginia Coal and Energy Commission
June 20, 1995. Roanoke

Virginia Center for Coal and Energy Research (VCCER) has contracted with the Virginia Port Authority to execute the study mandated by 1995 Virginia House Bill 2575. The study will concern the "effect the Coalfield Enhancement Tax Credit has or will have on the export coal businesses at the Ports of Hampton Roads."

The HB 2575 study will take place in several phases:

1. Estimate the amount of production tax credits to be applied to mines producing export coal being shipped through the Hampton Roads Port.

2. Assess the effects of the coal production tax credit on coal sales prices.

3. Assess the effects of coal production tax credits, including any resulting price changes, on export coal tonnages shipped through the Port.

4. Assess the effects of tonnage changes on businesses at the Port of Hampton Roads.

5. Estimate statewide economic impacts of the coal production tax credit.

Phase 1 will be conducted by gathering information from available sources and knowledgeable parties. Phases 2 and 3 will be conducted using two parallel procedures (empirical and econometric), as detailed below. Phases 4 and 5 will be based on the procedures and results of phases 2 and 3, previous VCCER research, and information to be obtained Old Dominion University researchers Gil Yochum and Vinod Agarwal. Drs. Yocum and Agarwal have conducted several studies of economic impacts at the Port; they have agreed to provide us with information on coal-related businesses at the Port.

The bulk of effort will be placed on study phases 2 and 3. Regardless of whether coal tax credits influence actual market prices, their effects on coal producers will occur via perceptions of change in <u>effective</u> prices; where tax credits are received by coal producers, the effect is an increase in the non-tax revenue received for each ton of coal produced.

In seeking to estimate how an effective change in price will influence coal production, we will use two parallel approaches. The econometric approach will look at past relationships among prices, Virginia coal sales, and related factors in seeking to derive quantitative expressions of economic relationships which can be applied in future projections. The empirical approach will seek to draw upon the experience of coal brokers, coal producers, and other knowledgeable parties in developing an estimate of coal markets' tax-credit response based upon their expectations.

The econometric approach to estimating the market price sensitivity of Virginia coal production may or may not yield useful results. Econometric analysis seeks to predict changes in sales of Virginia coal that will occur as a result of the production tax credit. The credit will allow Virginia coal producers to adjust the relationship of their prices to mining costs so as to compete more effectively in various markets. However, a variety of other factors will also affect sales of Virginia coal; a successful econometric analysis must account for these factors. The short time frame of this study may hinder our ability to make effective use of the capability of econometric methods. If this occurs, we will rely more heavily on the empirical approach.

The tax credit legislation contains qualifications which complicate the analysis. These include (i) the fact that production during any given year will not result in a tax credit until, at best, three years hence, and (ii) the fact that any future tax credit will be contingent upon an event over which producers have no control (a state revenue surplus).

In order to make the problem manageable in a conventional economic framework, analytical assumptions will include (i) the revenue-surplus contingency will have no effect on producer decisions, and (ii) the effect of the time delay on producer behavior can be analyzed on a straight net-present-value basis. We will investigate both assumptions during the study. Preliminary discussions indicate that coal producing firms whose survival is threatened may not change their behavior to accommodate a possible tax credit three years hence which is contingent upon a state revenue surplus. These discussions also indicate that the five-year duration of the tax credit defined by the current legislation may limit its effect on mine investment.

Statewide economic impacts of the tax credits (study phase 5) will be estimated based upon information generated in conducting study phases 1 through 4 and previous VCCER research. This information will be provided to the Southwest Virginia Office of the Center for Public Service.

Our intent is to focus investigations upon the production coal tax credit as it is described in the legislation. The study will assess only the production tax credit - the steam producer credit and the coalbed methane credit will not be considered. If the Subcommittee wishes us to address related topics, a formal request would be helpful.

A draft report will be provided to the Virginia Port Authority and other interested parties by September 1. Comments received in response to that draft report will be considered in preparing a final report by December 1, as specified in the legislation.

Figure 10. Total Virginia Coal Production: 1990 - 1994, and Projected Levels (with and without Tax Credits)

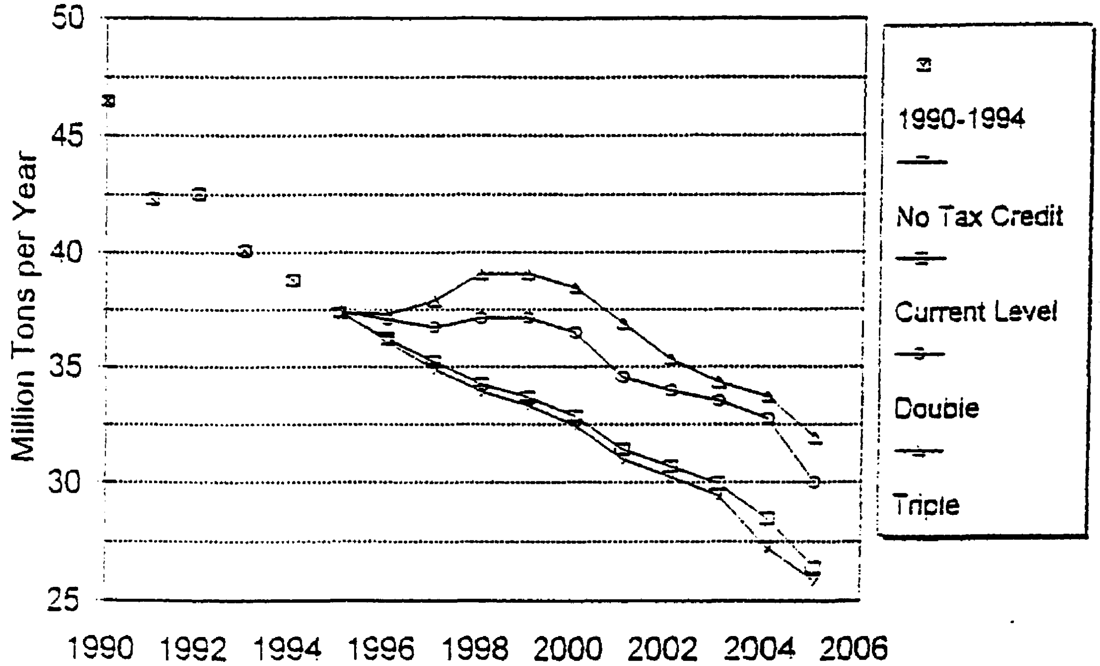
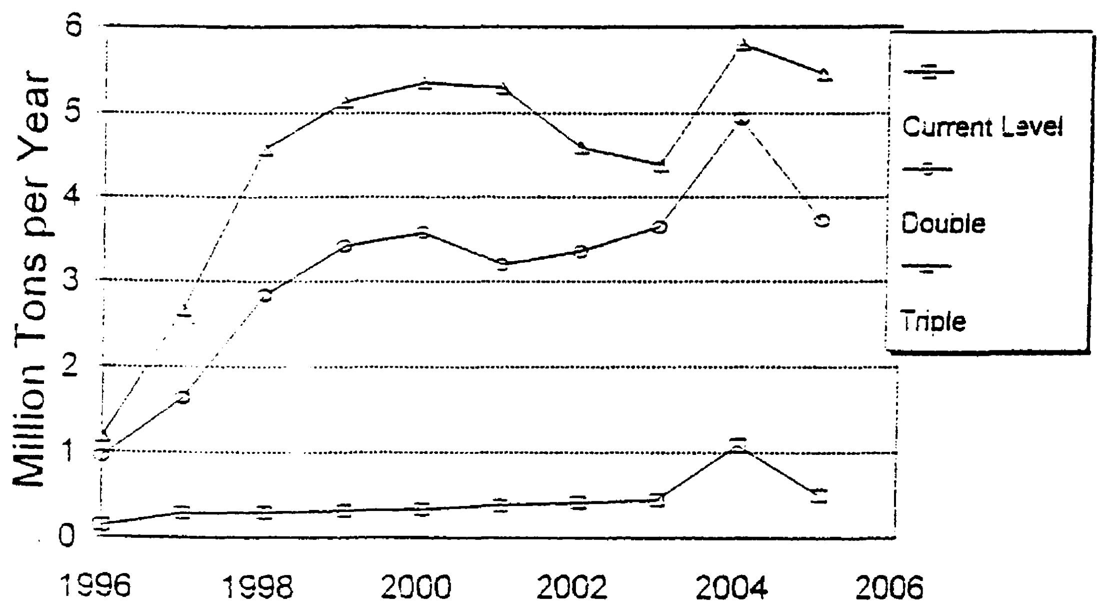



Figure 12. Projected Coal-Production Benefits of Tax Credits (Estimated Incremental Coal Production Due to Non-Delayed, Non-Contingent Tax Credits)




Total Virginia Estimates Derived from Producer Survey Results

Figure 13. Projected Impacts of Non-Delayed, Non-Contingent Tax Credits on Statewide Employment

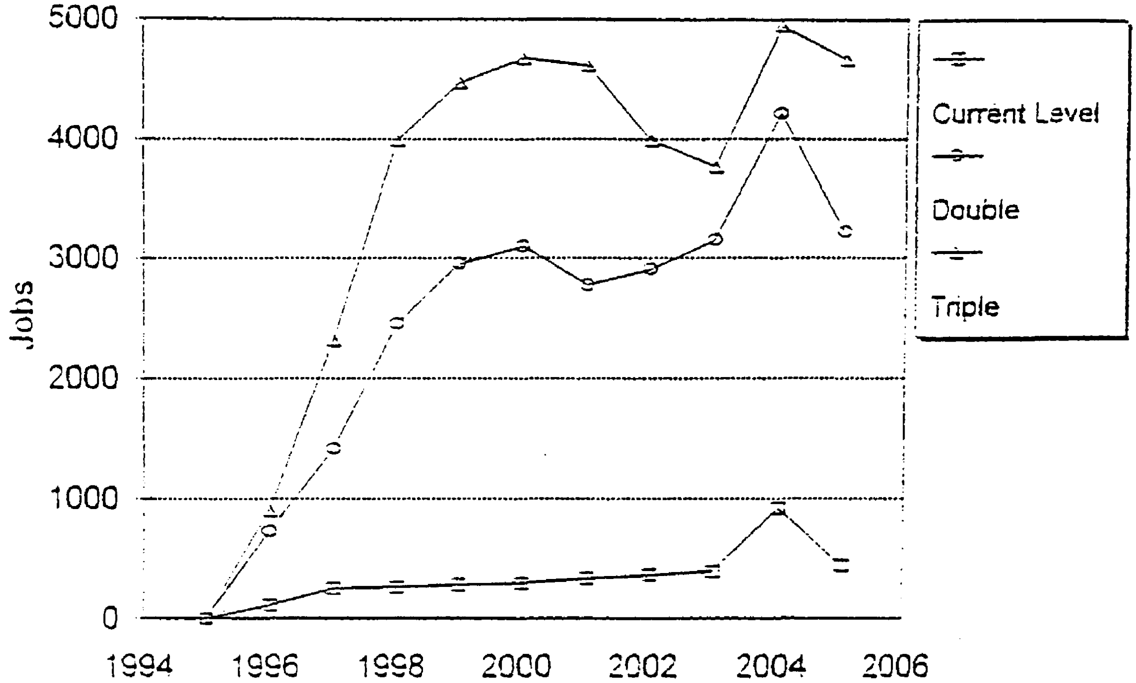



Figure 14. Projected Impacts of Non-Delayed, Non-Contingent Tax Credits on Statewide Payroll Income

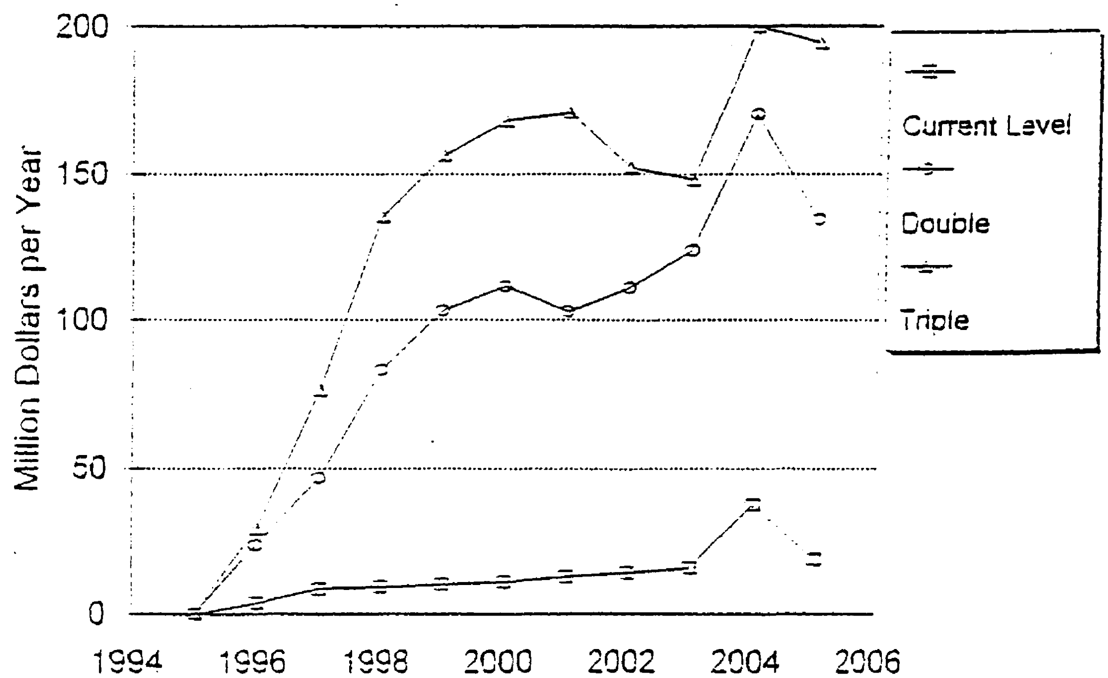


Figure 15. Projected Impacts on Non-Delayed, Non-Contingent Tax Credit on State/Local Government Revenue - At Current Level.

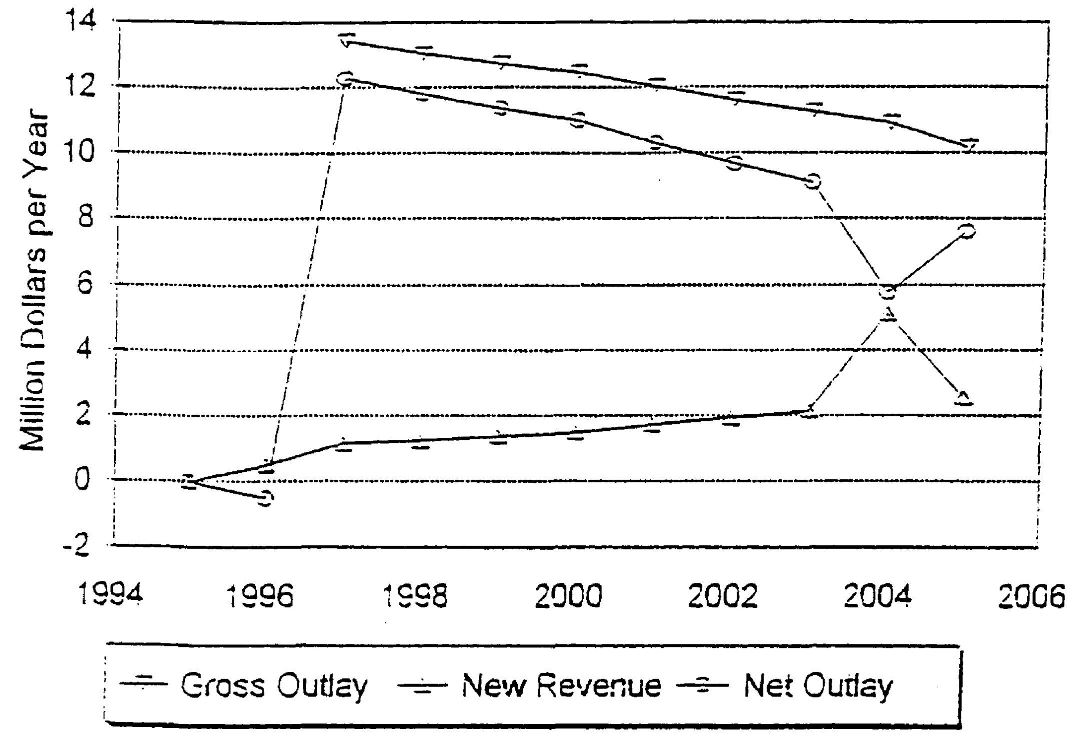



Figure 16. Projected Impacts of Non-Delayed, Non-Contingent Tax Credits on State/Local Government Revenue - At Double Current Level

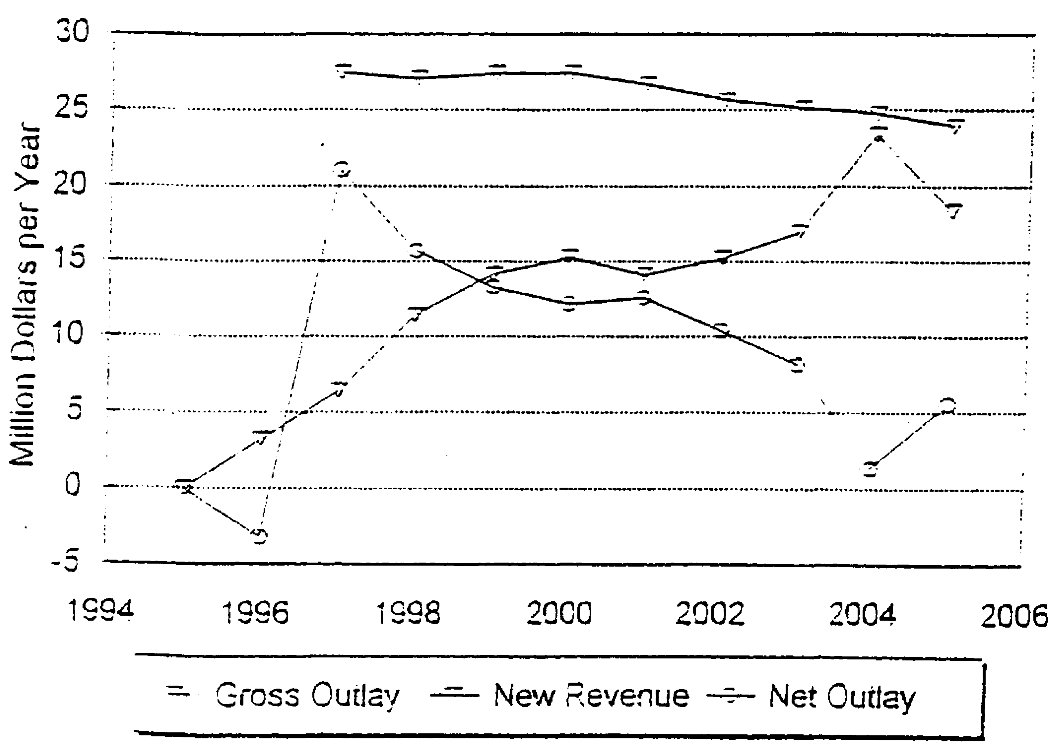


Figure 17. Projected Impacts of Non-Delayed, Non-Contingent Tax Credit on State/Local Government Revenue - At Triple Current Level

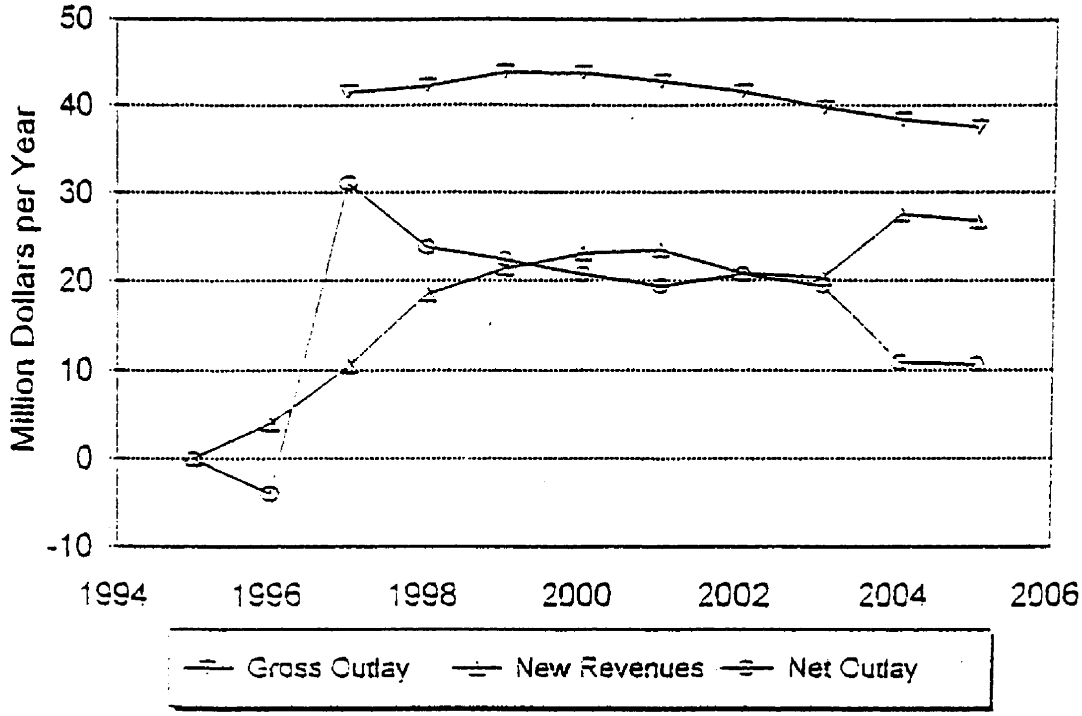
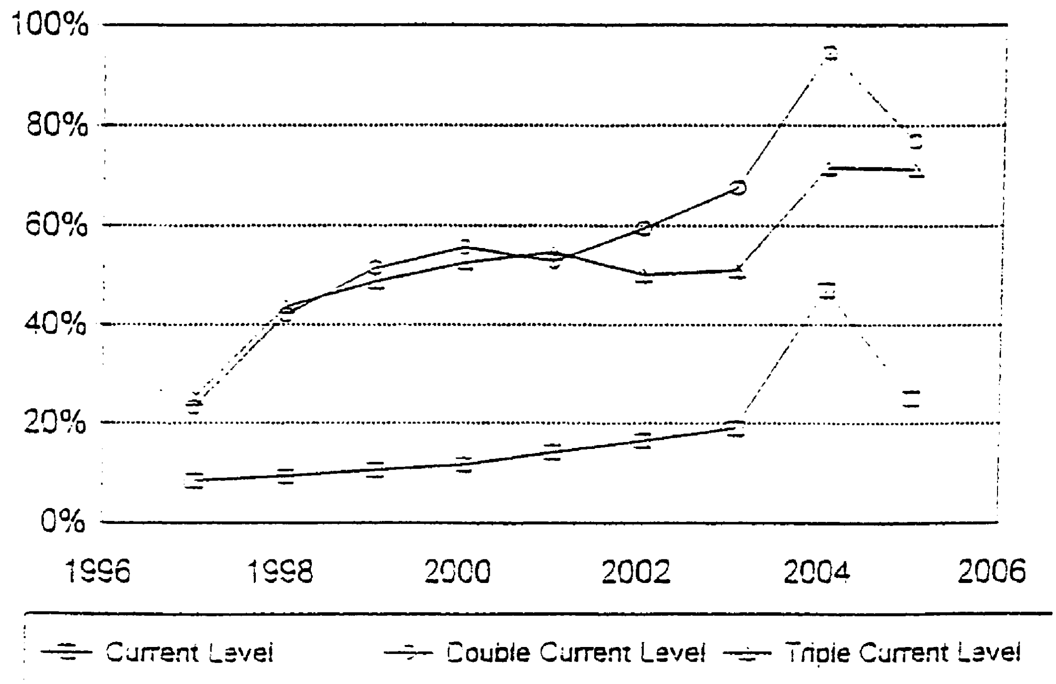



Figure 18. Projected Impacts of Non-Delayed, Non-Contingent Tax Credit on State/Local Government Revenues - New Revenues as Percent of Gross Outlay.



## Table 6. Summary of Tax Credit Fiscal Impacts on State and Local Governments ($ millions)

| | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Total Impacts of Coal Mining and Transport without Credit, and Cost of Current Tax Credit:* | | | | | | | | | | | |
| Direct | 48 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 47 | 46 |
| Indirect and Induced | 91 | 92 | 92 | 92 | 93 | 94 | 92 | 92 | 93 | 89 | 87 |
| Paid to State (est.) | 76 | 77 | 77 | 77 | 78 | 78 | 76 | 77 | 77 | 74 | 73 |
| Paid to Local (est.) | 64 | 64 | 64 | 64 | 65 | 65 | 64 | 64 | 64 | 62 | 60 |
| Total Tax Collections | 140 | 141 | 141 | 141 | 143 | 143 | 140 | 141 | 142 | 136 | 133 |
| Gross Cost of Tax Credit | | | | | 14.9 | 14.3 | 14.0 | 13.7 | 13.2 | 12.7 | 12.3 |
| *Incremental Impact: Non-Delayed, Non-Contingent Credit at Current Level* | | | | | | | | | | | |
| New Revenues - Direct | | 0.2 | 0.4 | 0.4 | 0.5 | 0.5 | 0.6 | 0.7 | 0.7 | 1.8 | 0.9 |
| New Revenues - Ind. and Ind. | | 0.3 | 0.8 | 0.8 | 0.9 | 1.0 | 1.1 | 1.3 | 1.4 | 3.4 | 1.7 |
| New Revs. to State (est.) | | 0.3 | 0.6 | 0.7 | 0.7 | 0.8 | 0.9 | 1.1 | 1.2 | 2.8 | 1.4 |
| New Revs. to Local (est.) | | 0.2 | 0.5 | 0.6 | 0.6 | 0.7 | 0.8 | 0.9 | 1.0 | 2.3 | 1.2 |
| Total New Revenues | | 0.5 | 1.2 | 1.2 | 1.4 | 1.5 | 1.7 | 1.9 | 2.2 | 5.1 | 2.6 |
| Gross Cost of Tax Credit | | 14.9 | 14.5 | 14.1 | 13.8 | 13.4 | 12.9 | 12.5 | 12.1 | 11.3 | 10.3 |
| *Incremental Impact: Non-Delayed, Non-Contingent Credit at Double Current Level* | | | | | | | | | | | |
| New Revenues - Direct | | 1.1 | 2.2 | 4.0 | 4.9 | 5.3 | 4.9 | 5.3 | 5.9 | 8.1 | 6.4 |
| New Revenues - Ind. and Ind. | | 2.1 | 4.2 | 7.4 | 9.2 | 10.0 | 9.2 | 10.0 | 11.1 | 15.3 | 12.0 |
| New Revs. to State (est.) | | 1.8 | 3.5 | 6.2 | 7.7 | 8.3 | 7.7 | 8.3 | 9.2 | 12.7 | 10.0 |
| New Revs. to Local (est.) | | 1.5 | 2.9 | 5.2 | 6.5 | 7.0 | 6.4 | 7.0 | 7.8 | 10.7 | 8.4 |
| Total New Revenues | | 3.2 | 6.4 | 11.4 | 14.2 | 15.3 | 14.1 | 15.2 | 17.0 | 23.4 | 18.4 |
| Gross Cost of Tax Credit | | 30.5 | 30.1 | 30.5 | 30.5 | 29.7 | 28.5 | 27.9 | 27.5 | 26.6 | 24.0 |
| *Incremental Impact: Non-Delayed, Non-Contingent Credit at Triple Current Level* | | | | | | | | | | | |
| New Revenues - Direct | | 1.4 | 3.6 | 6.4 | 7.4 | 8.0 | 8.1 | 7.2 | 7.1 | 9.5 | 9.3 |
| New Revenues - Ind. and Ind. | | 2.6 | 6.8 | 12.1 | 14.0 | 15.0 | 15.3 | 13.6 | 13.3 | 17.9 | 17.4 |
| New Revs. to State (est.) | | 2.2 | 5.7 | 10.1 | 11.6 | 12.5 | 12.7 | 11.3 | 11.0 | 14.9 | 14.5 |
| New Revs. to Local (est.) | | 1.8 | 4.8 | 8.5 | 9.8 | 10.5 | 10.7 | 9.5 | 9.3 | 12.5 | 12.2 |
| Total New Revenues | | 4.0 | 10.5 | 18.5 | 21.4 | 23.0 | 23.4 | 20.9 | 20.3 | 27.5 | 26.7 |
| Gross Cost of Tax Credit | | 46.2 | 46.9 | 48.6 | 48.6 | 47.5 | 46.2 | 44.1 | 42.6 | 41.6 | 39.2 |

Note: Above tax revenue estimates are based upon results of coal producer survey and $3.86/ton estimate of VCCER 95-1.

Corrected Sept 13 '95

# Effects of Coal Seam Thickness on Underground Mining Cost

Factors Affecting Cost in Low-Headroom Mines:

*Labor Productivity:* Productivity decreases as mining height declines. Data from central Appalachian mining operations studied by the U.S. Bureau of Mines in the early 1990s demonstrate mine productivity declines of about 1% for each inch of decreasing coal thickness (T.J. Rohrbacher et al. 1993. *Coal Resource Recoverability.* BOM Information Circular 9368). A 1991 study conducted for Electric Power Research Institute by Hill and Associates (*Central Appalachia: Production Potential of Low-Sulfur Coal*), and VCCER analysis of 1994 Virginia DMME mine data demonstrate similar trends. These decreases occur due to several factors. One is the inherent difficulties of working in confined vertical spaces. Also, decreases in labor productivity occur because of the need to service additional square footages of mine area for each ton of coal produced. Roof bolting costs, for example are generally affected more directly by mine area than by tonnage. The smaller equipment that is sometimes used in low-headroom mines cannot be operated as efficiently as full-sized equipment.

*Non-Labor Costs:* Per-ton costs for factors other than labor also increase as mining height declines. For example: power consumption for ventilation increases in low-headroom mines because small vertical spaces exert a greater resistance to air flow than do larger spaces. The per-ton costs of roof bolting supplies and rock dust are also higher in low-headroom mines. The costs of supplies to extend and operate beltlines are also affected by the high area-to-volume ratios of low-height mines.

*Materials Handling Costs:* As seam thickness declines below the minimum mining height required to accommodate equipment, additional costs are incurred . In addition to minable coal, rock from the mine roof or floor must be removed to create a vertical space sufficient to accommodate the mine operation. This rock must be cut from the mine face, transported from the mine, processed, and managed as solid waste - all at cost to the firm. The minimum vertical height requirement can vary, depending on mine conditions. 38 to 42 inches constitutes a range of figures cited as typical for Virginia by mining consultants, mining industry and Bureau of Mines personnel.

The Effect of Seam Thickness on Mining Cost:

The figures which follow are meant to illustrate the effects of coal thickness on mining cost. Because Virginia mine operators face a variety of conditions, these figures are not intended to define average costs. They are, however, meant to represent cost differences.

In developing the figures, most costs were held constant per raw ton of material removed from the mine. Labor productivity is defined in on a raw-ton basis as a function of mine height, based on the results of the Bureau of Mines study and the VCCER analysis referenced above. Supplies are considered to be a function of mine area. The figures show that, as mining height declines from 54 to 28 inches, per-ton costs increase by a factor of roughly 50 percent.

These figures are not realistic in some respects. Under current market conditions, it would be difficult to mine the thin seams at these costs profitably. The sharp increase in price at 38 inches is a result of the assumptions used; in reality, the cost-vs.seam-thickness relationship would show a more gradual curvature.

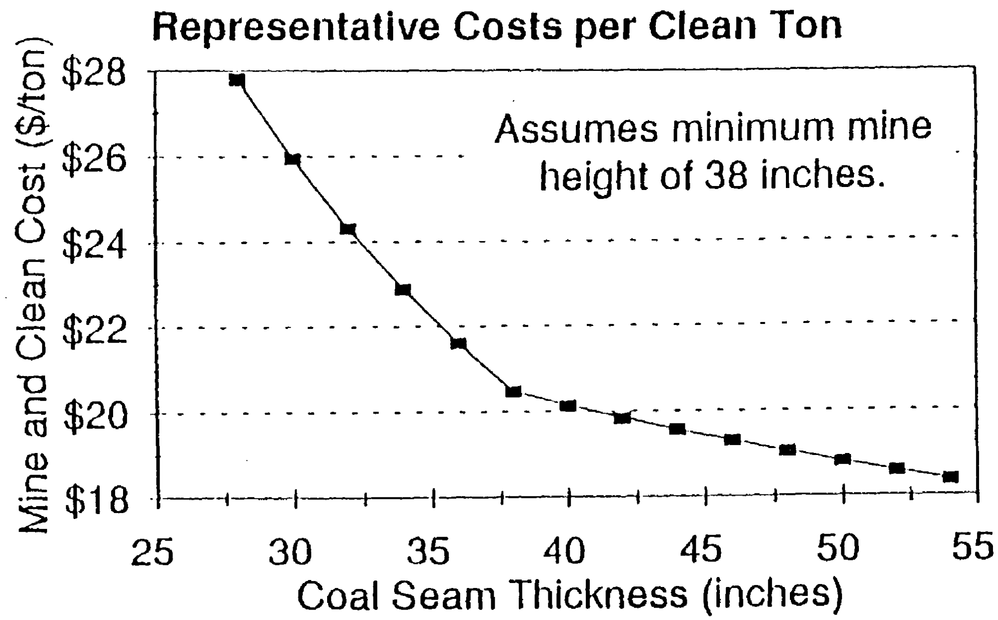
Carl E. Zipper, Virginia Center for Coal and Energy Research, Virginia Tech. 5/11/95
Presentation to Coal Subcommittee of the Coal and Energy Commission, Wytheville.

## Effects of Coal Seam Thickness on Underground Mining Cost

Continuous Miner Equipment

| **Base Factors** - 42 inch mine height | |
|---|---|
| Productivity (raw tons/ hour) | 4.00 |
| Labor Rate (wage plus fringe) | 22.00 |
| Clean Coal Yield from Seam | 70% |

| **Costs to Mine 42 Inch Seam** | **$ per raw ton** |
|---|---|
| Mine Labor & Support | 5.50 |
| Supplies | 2.00 |
| Power & Fuel | 0.70 |
| Equipment Own, Maint, Repair | 2.50 |
| Trucking | 0.70 |
| Processing | 2.50 |
| Total Mine and Clean Cost | 13.90 |




Actual costs vary widely from mine to mine. Represents mining and processing costs only. Fixed costs - such as royalties, severance tax, company overhead - are not included. Meant to represent differences - not meant to be average or precise.

**Mine and Clean Cost per Raw Ton:**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Seam Thickness (in) | 28 | 30 | 32 | 34 | 36 | 38 | 40 | 42 | 44 | 46 | 48 | 50 | 52 | 54 |
| Mine Height (in) | 38 | 38 | 38 | 38 | 38 | 38 | 40 | 42 | 44 | 46 | 48 | 50 | 52 | 54 |
| Productivity (Raw Tons/Hr) | 3.84 | 3.84 | 3.84 | 3.84 | 3.84 | 3.84 | 3.92 | 4 | 4.08 | 4.16 | 4.24 | 4.32 | 4.4 | 4.48 |
| Labor Cost | 5.73 | 5.73 | 5.73 | 5.73 | 5.73 | 5.73 | 5.61 | 5.50 | 5.39 | 5.29 | 5.19 | 5.09 | 5.00 | 4.91 |
| Non-Labor Cost | 8.61 | 8.61 | 8.61 | 8.61 | 8.61 | 8.61 | 8.50 | 8.40 | 8.31 | 8.23 | 8.15 | 8.08 | 8.02 | 7.96 |
| Total Cost / Raw Ton | 14.34 | 14.34 | 14.34 | 14.34 | 14.34 | 14.34 | 14.11 | 13.90 | 13.70 | 13.51 | 13.34 | 13.17 | 13.02 | 12.87 |

**Mine and Clean Cost per Clean Ton:**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Clean Coal Yield | 52% | 55% | 59% | 63% | 66% | 70% | 70% | 70% | 70% | 70% | 70% | 70% | 70% | 70% |
| Productivity (Clean Ton/Hr) | 1.98 | 2.12 | 2.26 | 2.41 | 2.55 | 2.69 | 2.74 | 2.80 | 2.86 | 2.91 | 2.97 | 3.02 | 3.08 | 3.14 |
| Mine Labor Cost / Clean Ton | 11.11 | 10.37 | 9.72 | 9.15 | 8.64 | 8.18 | 8.02 | 7.86 | 7.70 | 7.55 | 7.41 | 7.28 | 7.14 | 7.02 |
| Non-Labor /Clean Ton | 16.69 | 15.58 | 14.61 | 13.75 | 12.98 | 12.30 | 12.14 | 12.00 | 11.87 | 11.75 | 11.64 | 11.54 | 11.45 | 11.37 |
| Mine & Clean Cost / Clean Ton | 27.80 | 25.95 | 24.33 | 22.90 | 21.62 | 20.49 | 20.16 | 19.86 | 19.57 | 19.31 | 19.06 | 18.82 | 18.59 | 18.38 |

**Stephen G. Young**
Vice President - Government Affairs

**CONSOL Inc.**
Consol Plaza
1800 Washington Road
Pittsburgh, PA 15241-1421
412-831-4043
FAX: 412-831-4574

August 3, 1995

The Honorable Jackson E. Reasor, Jr.
Chairman, Coal Subcommittee of the
Virginia Coal and Energy Commission
P. O. Box 691
Bluefield, VA 24605

Dear Mr. Chairman:

Subject: HJR 586, Study of Coal Tax Credit

I am writing to you as a member of the Coal Subcommittee of the Virginia Coal and Energy Commission. As you probably know, the CONSOL Coal Group (Consolidation Coal Company and Island Creek Coal Company) is Virginia's largest coal producer -- we should produce about 8.6 millions tons of coal this year in the Commonwealth.

Much has been said in earlier years about aiding Virginia producers to sell to Virginia utilities -- this resulted in the tax credit for burning Virginia coal. A lot of focus this year was upon the competitive problems in thin seam mining. I think the committee should be made aware that seam thickness is not the only determinant of a mine's competitiveness.

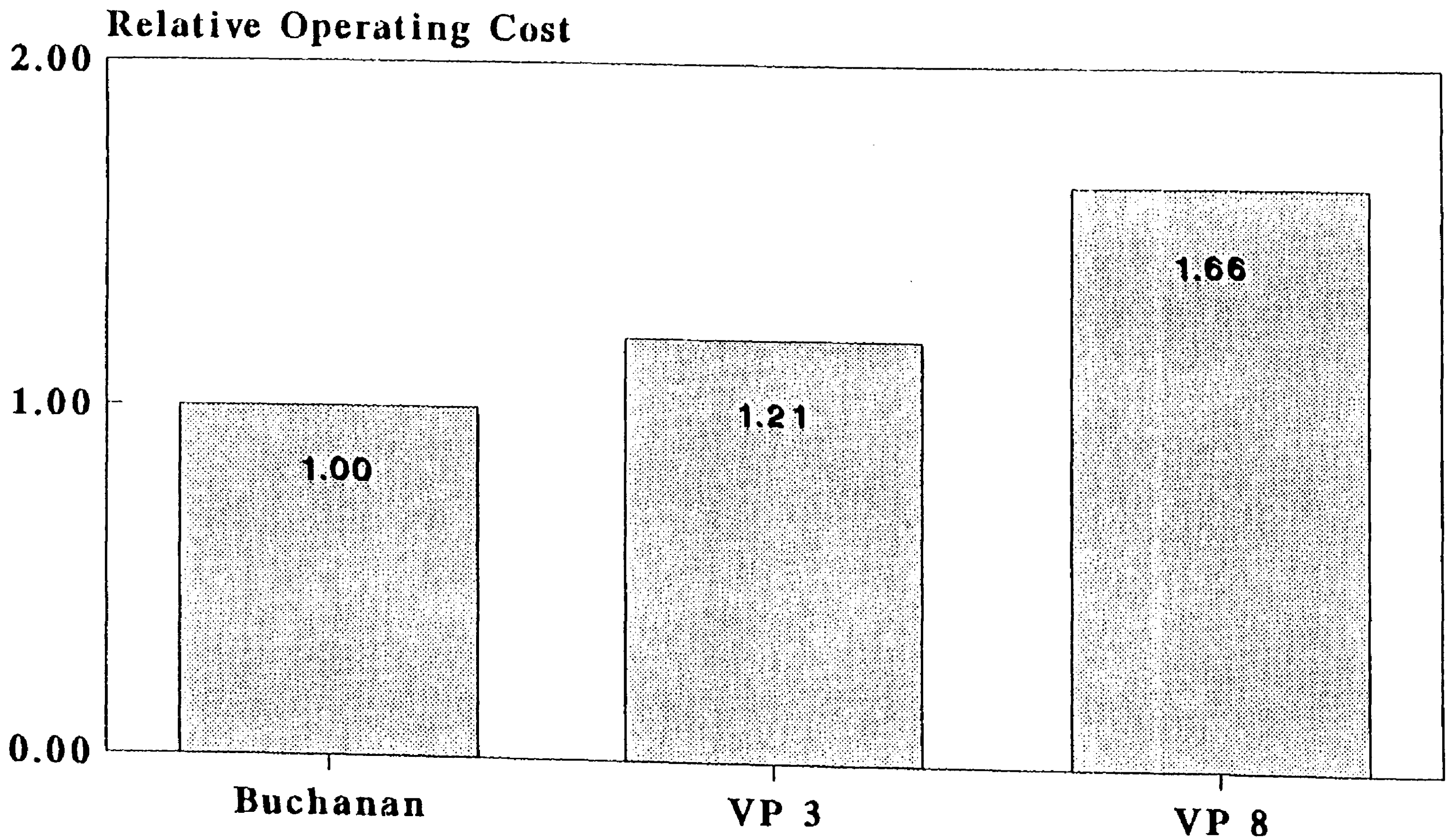
Indeed, we find that the challenges of mining our thicker Pocahontas # 3 seam, such as high rock pressures and high methane volumes at depths below 1200 feet as well as geologic surprises such as rolls in the floor and roof and faults, are considerable. The enclosure graphically illustrates the effects that mining conditions **other than seam thickness** can have on operating costs. Our VP 3 and VP 8 mines operate in the same seam, the Pocahontas #3, as our Buchanan mine. All three mines have an average seam height of approximately 5.5 feet and yet operating costs for the VP 3 mine in 1994 were 21 percent higher than Buchanan's. Operating costs for the VP 8 mine in 1994 were 66 percent higher than Buchanan's.

This year we supported the position of the Virginia Coal Association in the enactment of tax incentives to support the Commonwealth's coal industry. We understand that it was difficult to address the issue equitably -- our comment would be that the method of allocating tax credit relief ultimately adopted by the General Assembly is about as fair as might be expected considering the complexity and all the variables before the legislature. **We urge you to stand by the allocation passed by the legislature.**

Sincerely,

Steve

# 1994
# RELATIVE CASH OPERATING COSTS:
## Same Seam, Same Thickness




In 1994:

VP 3 Operating Costs Were 21% Higher Than Buchanan
VP 8 Operating Costs Were 66% Higher Than Buchanan

965501727

## SENATE BILL NO. 539

Offered January 22, 1996

*A BILL to amend and reenact § 58.1-439.1 of the Code of Virginia, relating to the coalfield employment enhancement tax credit.*

---

Patrons—Reasor and Wampler; Delegates: Stump and Tate

---

Referred to the Committee on Finance

---

**Be it enacted by the General Assembly of Virginia:**

**1. That § 58.1-439.1 of the Code of Virginia is amended and reenacted as follows:**

§ 58.1-439.1. Coalfield employment enhancement tax credit.

A. For tax years beginning on and after January 1, 1996, but before January 1, 2001, any person who has an economic interest in coal mined in the Commonwealth shall be allowed a credit against the tax imposed by § 58.1-400 and any other tax imposed by the Commonwealth in accordance with the following:

1. For coal mined by underground methods, the credit amount shall be based on the seam thickness as follows:

| Seam Thickness | Credit per Ton |
|---|---|
| ~~Under 33"~~ *36" and under* | ~~$.50~~ *$2.00* |
| ~~33" and~~ Above *36"* | ~~$.50~~ *$1.00* |

The seam thickness shall be based on the weighted average isopach mapping of actual coal thickness by mine as certified by a professional engineer. Copies of such certification shall be maintained by the person qualifying for the credit under this section for a period of three years after the credit is applied for and received and shall be available for inspection by the Department of Taxation. The Department of Mines, Minerals and Energy is hereby authorized to audit all information upon which the isopach mapping is based.

2. For coal mined by surface mining methods, a credit in the amount of ~~twenty-five~~ *forty* cents per ton for coal sold in 1996, and each year thereafter.

B. In addition to the credit allowed in subsection A, for tax years beginning on and after January 1, 1996, any person who is a producer of coalbed methane shall be allowed a credit in the amount of one cent per million BTUs of coalbed methane produced in the Commonwealth against the tax imposed by § 58.1-400 and any other tax imposed by the Commonwealth on such person.

C. For purposes of this section, economic interest is the same as the economic ownership interest required by § 611 of the Internal Revenue Code which was in effect on December 31, 1977. A party who only receives an arm's length royalty shall not be considered as having an economic interest in coal mined in the Commonwealth.

D. If the credit exceeds the person's state tax liability for the tax year, the excess may be redeemable by the Tax Commissioner on behalf of the Commonwealth for ninety-five percent of the face value within ninety days after filing the return. If the Commonwealth does not redeem such excess amount, it shall be transferable by sale.

E. No person may utilize more than one of the credits on a given ton of coal described in subsection A. No person may claim a credit pursuant to this section for any ton of coal for which a credit has been claimed under § 58.1-433 or § 58.1-2626.1. ~~Persons who qualify for the credit may not apply such credit to their tax returns prior to January 1, 1999, and only one year of credits shall be allowed annually beginning in 1999. No credit authorized by subsections A and B shall be taken by any taxpayer in 1999 unless general fund revenue in fiscal year 1997-98 exceeds the official estimate of general fund revenue by at least the cost of the credits authorized by subsections A and B as estimated by the Department of Taxation. In each following year no credit shall be taken by any taxpayer unless general fund revenue in the fiscal year ending the prior June 30 exceeds the official estimate of general fund revenue by at least the cost of the credits authorized by subsections A and B.~~

965627176

**HOUSE BILL NO. 1454**

AMENDMENT IN THE NATURE OF A SUBSTITUTE

(Proposed by the House Committee on Finance

on February 13, 1996)

(Patron Prior to Substitute—Delegate Cranwell)

*A BILL to amend and reenact § 58.1-439.2 of the Code of Virginia, relating to the coalfield employment enhancement tax credit.*

**Be it enacted by the General Assembly of Virginia:**

**1. That § 58.1-439.2 of the Code of Virginia is amended and reenacted as follows:**

§ 58.1-439.2. Coalfield employment enhancement tax credit.

A. For tax years beginning on and after January 1, 1996, but before January 1, ~~2001~~ *2002*, any person who has an economic interest in coal mined in the Commonwealth shall be allowed a credit against the tax imposed by § 58.1-400 and any other tax imposed by the Commonwealth in accordance with the following:

1. For coal mined by underground methods, the credit amount shall be based on the seam thickness as follows:

| Seam Thickness | |
|---|---|
| ~~Under 33"~~ *36" and under* | ~~$.60~~ *$2.00* |
| ~~33" and~~ Above *36"* | ~~$.50~~ *$1.00* |

The seam thickness shall be based on the weighted average isopach mapping of actual coal thickness by mine as certified by a professional engineer. Copies of such certification shall be maintained by the person qualifying for the credit under this section for a period of three years after the credit is applied for and received and shall be available for inspection by the Department of Taxation. The Department of Mines, Minerals and Energy is hereby authorized to audit all information upon which the isopach mapping is based.

2. For coal mined by surface mining methods, a credit in the amount of ~~twenty-five~~ *forty* cents per ton for coal sold in 1996, and each year thereafter.

B. In addition to the credit allowed in subsection A, for tax years beginning on and after January 1, 1996, any person who is a producer of coalbed methane shall be allowed a credit in the amount of one cent per million BTUs of coalbed methane produced in the Commonwealth against the tax imposed by § 58.1-400 and any other tax imposed by the Commonwealth on such person.

C. For purposes of this section, economic interest is the same as the economic ownership interest required by § 611 of the Internal Revenue Code which was in effect on December 31, 1977. A party who only receives an arm's length royalty shall not be considered as having an economic interest in coal mined in the Commonwealth.

D. If the credit exceeds the person's state tax liability for the tax year, the excess may be redeemable by the Tax Commissioner on behalf of the Commonwealth for ninety-five percent of the face value within ninety days after filing the return. If the Commonwealth does not redeem such excess amount, it shall be transferable by sale.

E. No person may utilize more than one of the credits on a given ton of coal described in subsection A. No person may claim a credit pursuant to this section for any ton of coal for which a credit has been claimed under § 58.1-433 or § 58.1-2626.1. Persons who qualify for the credit may not apply such credit to their tax returns prior to January 1, 1999, and only one year of credits shall be allowed annually beginning in 1999. ~~No credit authorized by subsections A and B shall be taken by any taxpayer in 1999 unless general fund revenue in fiscal year 1997-98 exceeds the official estimate of general fund revenue by at least the cost of the credits authorized by subsections A and B as estimated by the Department of Taxation. In each following year no credit shall be taken by any taxpayer unless general fund revenue in the fiscal year ending the prior June 30 exceeds the official estimate of general fund revenue by at least the cost of the credits authorized by subsections A and B.~~

*F. The amount of credit allowed pursuant to subsection A shall be the amount of credit earned multiplied by the person's employment factor. The person's employment factor shall be the percentage obtained by dividing the total number of coal mining jobs of the person filing the return, including the jobs of the contract operators of such person, as reflected in the annual tonnage reports filed with* *the Department of Mines, Minerals and Energy for the year in which the credit was earned by the total number of coal mine jobs of such persons or operators as reflected in the annual tonnage reports for the year immediately prior to the year in which the credit was earned. In no case shall the credit claimed exceed that amount set forth in subsection A.*

*G. The tax credit allowed under this section shall be claimed according to the following schedule:*

*1. 50% of the credit allowed in tax year 1996 shall be claimed in tax year 1999 and the remainder in the year 2005.*

*2. 50% of the credit allowed in tax year 1997 shall be claimed in tax year 2000 and the remainder in tax year 2006.*

*3. 75% of the credit allowed in tax year 1998 shall be claimed in tax year 2001 and the remainder in tax year 2007.*

*4. 75% of the credit allowed in tax year 1999 shall be claimed in tax year 2002 and the remainder in tax year 2008.*

*5. 100% of the credit allowed in tax year 2000 shall be claimed in tax year 2003.*

*6. 100% of the credit allowed in tax year 2001 shall be claimed in tax year 2004.*

**2. That the provisions of this act shall become effective for all taxable years beginning on or after January 1, 1996, through December 31, 2001, however, credits earned for such taxable years may continue to be utilized after taxable year 2001 as provided in this act.**

Official Use By Clerks

| **Passed By The House of Delegates** | | **Passed By The Senate** | |
|---|---|---|---|
| without amendment | ☐ | without amendment | ☐ |
| with amendment | ☐ | with amendment | ☐ |
| substitute | ☐ | substitute | ☐ |
| substitute w/amdt | ☐ | substitute w/amdt | ☐ |
| Date: ____________ | | Date: ____________ | |
| Clerk of the House of Delegates | | Clerk of the Senate | |

COMMONWEALTH OF VIRGINIA

E. M. MILLER, JR.
DIRECTOR

GENERAL ASSEMBLY BUILDING
910 CAPITOL STREET, 2ND FLOOR
RICHMOND, VIRGINIA 23219

(804) 786-3591
FAX (804) 371-0169

DIVISION OF LEGISLATIVE SERVICES

**June 8, 1995**

**Memorandum**

**To: Members, Coal Subcommittee of the Virginia Coal and Energy Commission**

**From: Arlen Bolstad, Senior Attorney**

**Re: Gasoline tax funding for coke production facility in Southwest Virginia.**

This memorandum summarizes staff research concerning gasoline tax funding for a proposed coke production facility in Southwest Virginia.

**Background.** When the subcommittee met in Wytheville on May 11, Dr. Wolfe reported on an advanced-technology coking process developed by his company. Limited production is currently underway with a prototype system. Dr. Wolfe proposed construction of a $12 million plant employing this new technology. Such a plant, he stated, would create and preserve jobs in Southwest Virginia's coal industry.

To fund the coking plant's construction, Dr. Wolfe suggested a one cent per-gallon tax on gasoline sold within the Ninth Congressional District. $6 million of the tax revenues generated would be loaned to Wolfe's operating company through an authority or some other entity. The $6 million balance needed for construction would then be obtained from private lenders.

Dr. Wolfe stated that this was not a new concept; that the D.C.-area Metro was partially funded by gasoline taxes imposed in parts of Northern Virginia. He and other members of the subcommittee requested staff to obtain information about the enabling legislation authorizing the Metro gas tax.

**Metro/Commuter rail gasoline tax.**

Dr. Wolfe was apparently referring to the provisions of Article 4 in Chapter 17 (Miscellaneous Taxes) of Title 58.1. A copy is attached. § 58.1-1720 is the key section in this article. It authorizes a two percent sales tax on fuels that ultimately provided funding to the Metro and to the commuter rail between Fredericksburg and D.C.. You will note in § 58.1-1724 that these taxes are paid into and disbursed from special fund accounts administered by the Tax Commissioner.

If the subcommittee endorsed Dr. Wolfe's proposal in some form, the Virginia Coalfield Economic Development Authority could conceivably serve as the funding/administrative vehicle for this project--much as the transportation districts have for the Northern Virginia transportation projects. For your information, I attached a copy of the Virginia Coalfield Economic Development Authority legislation.

Please call me if you have any questions.

AKB:hs

E:\DLSDATA\BUSJURIS\PERMCOMM\CL_ENRGY\WOLFTAX.DOC

# ENERGY ASSISTANCE PROGRAM

## 1994-95 PROGRAM YEAR

Prepared by the Virginia Department of Social Services,
Division of Benefit Programs

# HOUSEHOLDS SERVED

## FUEL ASSISTANCE

| | |
|---|---|
| APPLICATIONS RECEIVED | 131,567 |
| APPLICATIONS APPROVED | 118,699 |
| DOLLARS ENCUMBERED | $21,305,831 |
| DOLLARS PAID | $20,744,112 |

AVERAGE BENEFIT $181

## CRISIS ASSISTANCE

| | |
|---|---|
| APPLICATIONS RECEIVED | 5,691 |
| APPLICATIONS APPROVED | 4,603 |
| DOLLARS ENCUMBERED | $1,798,599 |
| DOLLARS PAID | $1,550,536 |

As of May 9, 1995

# CRISIS ASSISTANCE
# 1994-95

SERVED 25% OF TOTAL HOUSEHOLDS SERVED IN 1993-94

DUE TO REDUCTION IN SERVICES PROVIDED

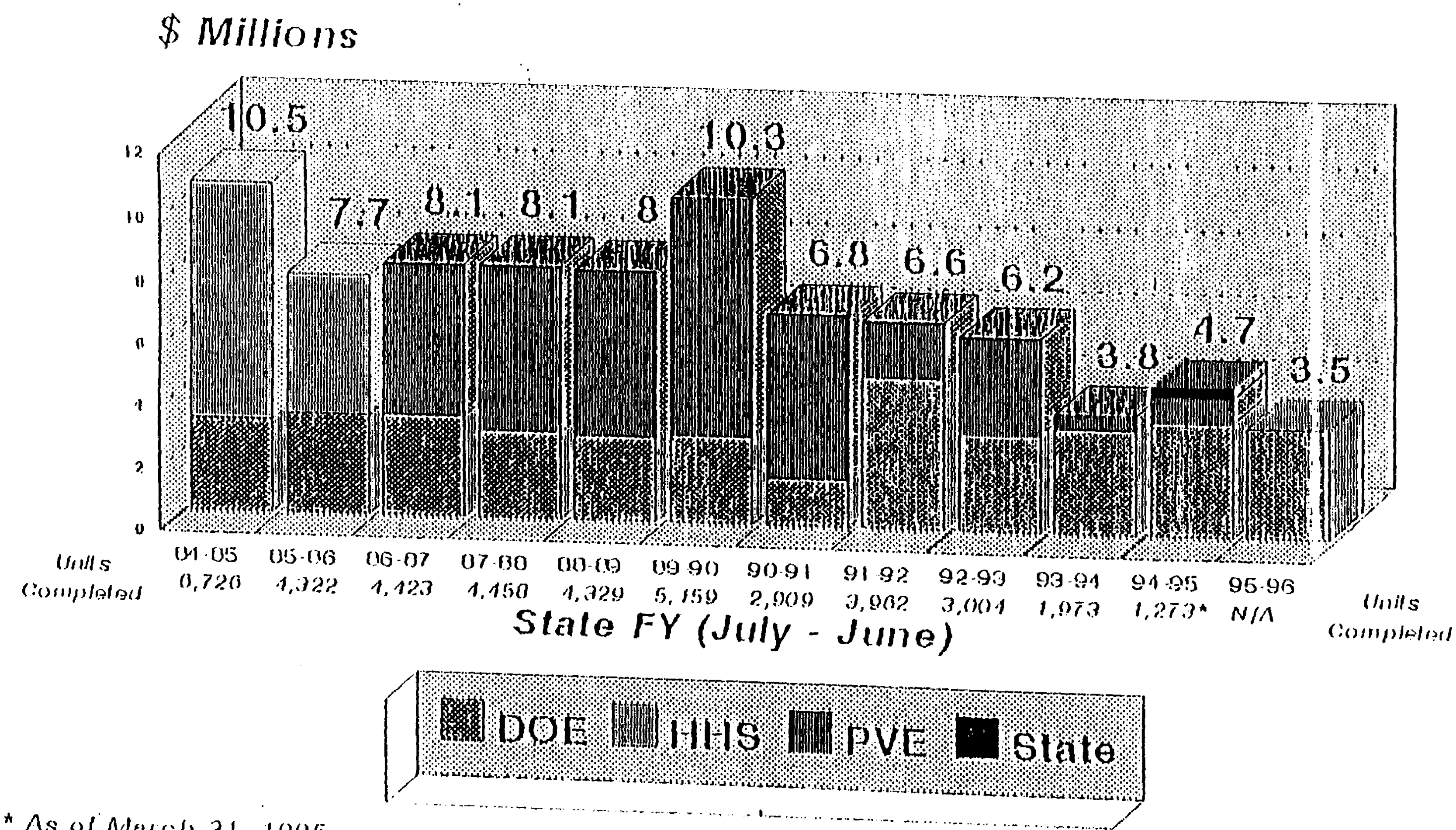
SERVICES PROVIDED ARE:

- Security deposits for primary fuel type
- Purchase or repair of heating equipment*
- Purchase of portable heaters
- Emergency shelter

* Contract with DHCD, subgrantee WAP agencies

# APPROPRIATION PATTERNS

(Years 84-90 exclude any carryover from previous years)



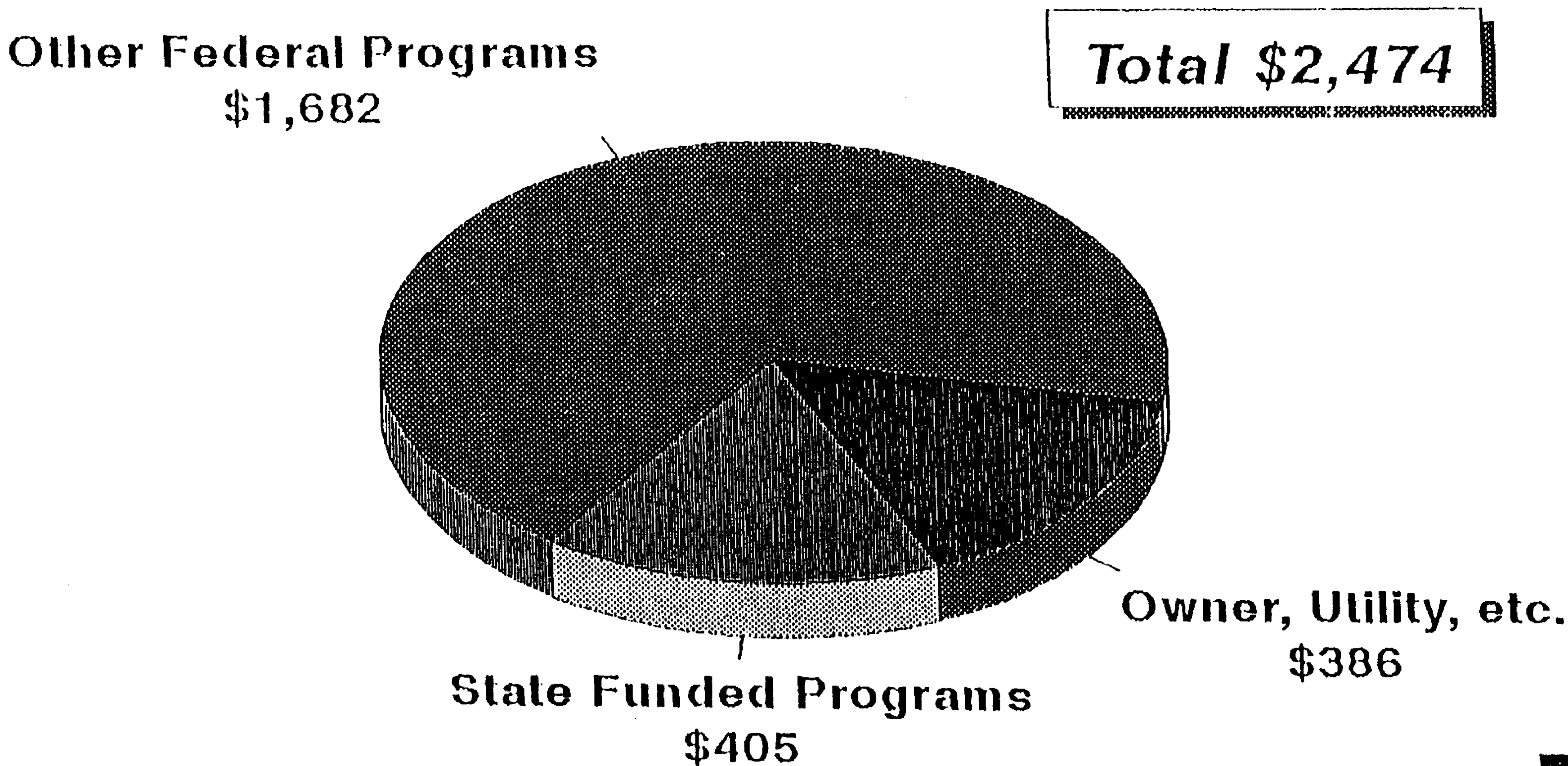

* As of March 31, 1995



APPENDIX L

# WAP Match/Leverage

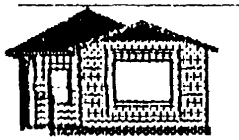
## July 1993 - June 1994

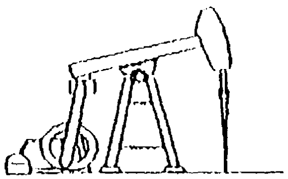



Reported in $ Thousands

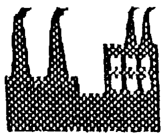
# Metrics for Virginia WAP

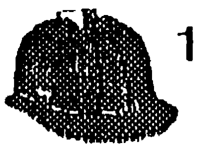
## July 1993 - June 1994

 1,973 *Dwellings weatherized*

 34,725 Btu *Energy saved*

 $228,868 *Dollars saved*

 1,341 tons C *Carbon reduction*

 171 w/o utility impacts
97 w/utility impacts *Job-years generated*

# Metrics for Virginia WAP

July 1993 - June 1994

| | |
|---|---|
| Dwellings weatherized: | 1,973 dwellings |
| Annual energy saved:[1] | 34,725 Million Btu |
| Annual dollars saved:[2] | $228,868 |
| Carbon reductions:[3] | 1,341 tons |
| Job-years generated:[4] | 171 jobs without utility sector impacts<br>97 jobs with utility sector impacts |

[1] *Calculated using Oak Ridge Lab estimate of 17.6 Million Btu saved per weatherized dwelling; Virginia number may differ if energy profile is much different from Oak Ridge assumptions.*

[2] *Calculated using Oak Ridge Lab estimate of $116 saved per dwelling weatherized; Virginia savings may differ if energy profile is much different from Oak Ridge assumptions.*

[3] *Calculated using Virginia's energy (fossil fuel) profile for its residential consumers, with the exception of electricity, in which a national average profile was used. Carbon reductions were calculated based on the fossil fuel profile and the energy saved per dwelling.*

[4] *A "job-year" represents one person working one standard work year. This number was calculated using a seven (7) sector national input/output table. Expenditures for weatherization projects are assumed to be equally divided between the Construction sector and the Manufacturing sector.*

*The number of "jobs without utility sector impacts" represents direct and indirect job creation assuming that the utility industry is not affected by the reduced energy consumption. The number of "jobs with utility sector impacts" represents direct and indirect job creation assuming that reduced energy consumption also reduced the number of jobs in the utility sector and its supporting sectors.*

*This calculation assumes that the Virginia input/output table profile is similar to the national input/output table; if Virginia's table profile is substantially different, the results will be different.*

# WAP ELIGIBLE HOUSEHOLDS UNSERVED

1981 - June, 1994

- **Total Eligible - 293,824**

Source: 1990 Census and U.S. Department of energy

- **Total Served - 71,245 *or 24%***

Source: Reports to DOE

- **Total Unserved - 225,579 *or 76%***

★ Adjusted for eligible persons living in public housing.

COMMONWEALTH OF VIRGINIA
HOUSE OF DELEGATES
RICHMOND

JAMES F. ALMAND
SUITE 206
2060 N. 14TH STREET
ARLINGTON, VIRGINIA 22201

FORTY-SEVENTH DISTRICT

COMMITTEE ASSIGNMENTS:
COURTS OF JUSTICE (CHAIRMAN)
GENERAL LAWS
FINANCE
MILITIA AND POLICE

September 20, 1995

The Honorable James S. Gilmore, III
Office of the Attorney General
900 East Main Street
Richmond, Virginia 23219

Re: Attorney General's Opinion; Allocation of Low Income Home Energy Assistance Program funding to the Weatherization Assistance Program.

Dear Attorney General Gilmore:

I am writing to you at the request of the Virginia Coal and Energy Commission to request a formal opinion from your office concerning an issue affecting two critical programs: the Low Income Home Energy Assistance Program (LIHEAP) and the Weatherization Assistance Program (WAP). The Commission monitors these important energy assistance programs through its Energy Preparedness Subcommittee which I chair. I would like to know whether the Department of Social Services must formally amend its LIHEAP regulations in order to allocate a percentage of the Commonwealth's federal LIHEAP grant to WAP.

By way of background, LIHEAP is a federally-funded, state-administered program providing short-term home heating fuel assistance to low-income individuals and families--most with annual incomes under $8,000. LIHEAP is administered in Virginia by the Department of Social Services (DSS). According to recent DSS figures reported to the Energy Preparedness Subcommittee, during program year 1994-1995 DSS paid out more than $21 million in LIHEAP benefits. The average benefit paid per household was $181.

WAP, administered by the Department of Housing and Community Development (HCD), is principally funded by the U.S. Department of Energy. WAP is designed to reduce the energy costs of low-income households by weatherizing homes and providing essential repairs to heating systems. According to HCD, WAP's statewide budget in 1994-1995 was $4.7 million. A budget of $3.5 million is projected in 1995-1996. Due to declining federal funding for WAP, for the past two years General Fund appropriations have been necessary to keep the program operational statewide--a condition necessary to qualify for federal funding.

The Commission believes that WAP and LIHEAP should be better coordinated to ensure (to the extent reasonably practicable) that individuals and families eligible for fuel assistance benefits have weatherized homes and heating systems in good repair. This would help reduce each home's heating costs while freeing up fuel assistance dollars for other eligible program participants

Federal LIHEAP regulations permit up to fifteen percent of states' LIHEAP grants to be spent on weatherization. An additional ten percent may be spent on weatherization upon application to and approval by the program's federal administrators.

The Commission recently learned that the Department of Social Services Board met on July 20 to discuss the allocation of some LIHEAP funding to the WAP program. The Board approved the transfer of up to eight percent of LIHEAP funding for weatherization. DSS estimates that the total LIHEAP grant for the 1995-1996 heating season will be approximately $18 million. Thus, the amount allocated to weatherization pursuant to the Board's action would be $1.4 million.

HCD representatives have submitted a proposed implementation plan to DSS for the latter's consideration. The HCD plan has two principal components. First, part of the transferred funds would be used by WAP for basic weatherization services such as caulking, insulation, window repairs, etc. These services would be furnished exclusively to persons receiving fuel assistance through LIHEAP. The proposal's second component would provide higher-cost weatherization services such as furnace repairs and replacements.

The Commission has also learned that DSS representatives believe that the LIHEAP funds cannot be allocated to WAP for weatherization unless and until the LIHEAP fuel assistance program regulations (*VR 615-08-1*, attached) are amended pursuant to the Administrative Process Act (APA)--a process that could take several months. This could mean that these LIHEAP funds will not be available for weatherization during the 1995-1996 heating season. Moreover, we understand that the funding will not be transferred to WAP until this procedural issue is resolved.

Inasmuch as the heating season is swiftly approaching, the Commission believes that the APA issue raised by DSS should be resolved in an expeditious fashion. As a practical matter, weatherization should be taking place at this time. Accordingly, at its recent meeting in Blacksburg, the Commission directed me to request your opinion on the following:

- *First*, allocating a percentage of LIHEAP funds to weatherization is already authorized by federal LIHEAP regulations--no further state enabling legislation or regulation is required. Moreover, while allocating funds to weatherization will reduce the funding for LIHEAP's fuel assistance program component, the allocation will not change the fuel assistance program's provisions. Accordingly, is it then necessary to amend *VR 615-08-1* in order to fund a LIHEAP weatherization component?

- *Second,* the Administrative Process Act (Va. Code § 9-6.14:1, et seq.), exempts in subdivision B 14 of § 9-6.14:1, "[G]rants of state or federal funds or property." Since LIHEAP is funded through federal grant dollars, is it necessary to invoke the APA's amending process (i.e., published notice of intent to amend, public hearings, etc.) in order to amend *VR 615-08-1* (assuming such amendment is necessary)?

- *Third,* assuming that the Board's decision must be implemented through an amendment to *VR 615-08-1,* could the need to weatherize low-income individuals' and families' homes be characterized as an "emergency situation" within the meaning of subdivision C 5 of Va. Code § 9-6.14:4.1 (which exempts the adoption of emergency regulations from the procedural requirements of the APA)?

- *Finally,* could the allocation of LIHEAP funding to a weatherization component be accomplished via Executive Order in lieu of amending *VR 615-08-1* (or adopting some other implementing regulation) to carry out the DSS Board's intent?

Thank you for your kind assistance in this matter. I look forward to hearing from you.

Sincerely yours,

/s/

James Almand

JAF/cgl
Enclosure
E:\DLSDATA\BUSJURIS\PERMCOMM\CL_ENRGY\ENPRPSUB\AGOPIN.DOC

# COMMONWEALTH of VIRGINIA

James S. Gilmore, III
Attorney General

*Office of the Attorney General*
*Richmond 23219*

900 East Main Street
Richmond, Virginia 23219
804 - 786 - 2071
804 - 371 - 8946 TDD

January 25, 1996

The Honorable James F. Almand
Member, House of Delegates
General Assembly Building
Capitol Square, Room 444
Richmond, Virginia 23219

My dear Delegate Almand:

You ask whether the State Board of Social Services (the "Board") is required to amend its Virginia Energy Assistance Program ("VEAP") regulations before allocating Low-Income Home Energy Assistance Program ("LIHEAP") funds to the Low-Income Weatherization Assistance Program ("WAP").[1] You also ask whether the Board must comply with the requirements of the Administrative Process Act (the "APA") to amend its VEAP regulations.[2] Finally, you ask whether LIHEAP funds may be allocated to WAP by executive order of the Governor.

---

[1]Federal law requires that each state submit annually an application to the Secretary of Health and Human Services for a grant of LIHEAP funds to assist certain low-income households with low-cost weatherization and other cost-effective energy-related home repair. 42 U.S.C.A. §§ 8621-8629 (1995). The Commonwealth submitted its application for fiscal year 1996, which was approved in November 1995 (*see* letter from Donald Sykes, Director, Office of Community Services, U.S. Department of Health & Human Services), providing for such fund allocation as follows: 81% for heating assistance; 10% for administrative and planning costs; 8% for crisis assistance; and 1% for carryover to fiscal year 1997. No LIHEAP funds will be expended for services to reduce home energy needs, including needs assessment. *See* Dep't Soc. Serv., Low Income Home Energy Assistance Program (LIHEAP), 1996 State Plan and Application, at 12 (Sept. 1995) [hereinafter State plan] (on file with Department of Social Services). This allocation of funds is mirrored in the VEAP regulations promulgated by the Board, which provide for fuel assistance and crisis assistance components. *See* 11:2 Va. Regs. Reg. VR 615-08-1, pts. II–III (1994). Neither the VEAP regulations nor the State plan provides for the use of LIHEAP funds for weatherization activities.

With respect to the federal requirement for public notice and comment on the use of LIHEAP funds, the State plan provides for a 30-day review of the VEAP regulations, use of an advisory group comprised of representatives from the public and private sector and a sounding board comprised of representatives from local social services departments, and a public hearing. *See* 42 U.S.C.A. § 8624(a)(2), (c)(2); State plan at 17-18.

[2]Sections 9-6.14:1 to 9-6.14:25. Generally, a state agency must promulgate and amend its regulations pursuant to the APA, which requires public notice and participation. *See* § 9-6.14:7.1. Section 9-6.14:4.1(B)(4), however, provides that agency action relating to, among others, grants of federal funds is exempted from the provisions of the APA.

You relate that the Virginia Coal and Energy Commission (the "Commission") believes that WAP and LIHEAP should be better coordinated to ensure that individuals and families eligible for fuel assistance benefits have weatherized homes and heating systems in good repair, to help reduce the heating costs of such housing while freeing up fuel assistance dollars for other eligible program participants. You note that federal law permits up to fifteen percent of a states' LIHEAP grant to be spent on weatherization. An additional ten percent may be spent on weatherization when approved by LIHEAP federal administrators.[3]

You also relate that the Commission recently was advised that the Board met during the summer of 1995 to discuss the allocation of some LIHEAP funding to WAP. The Board approved the transfer of up to eight percent of LIHEAP funding for weatherization. You advise that representatives from the Department of Housing and Community Development have submitted for consideration a proposed implementation plan for the transferred funds, with two principal components: (1) the transferred funds would be used by WAP for basic weatherization services, such as caulking, insulation and window repair, furnished exclusively to persons receiving fuel assistance through LIHEAP; and (2) the transferred funds would provide higher-cost weatherization services, such as furnace repairs and replacements.

Finally, you advise that the Commission has been advised that the LIHEAP funds cannot be allocated to WAP for weatherization unless and until the VEAP regulations are amended pursuant to the APA. You advise that the APA process may take several months, which would mean that the LIHEAP funds will not be available for weatherization during the 1995-1996 heating season. Furthermore, you advise that the Commission understands that funding will not be transferred to WAP until this procedural issue is resolved.

Federal law permits the allocation of LIHEAP funds for weatherization activities[4]; however, a state must expend LIHEAP funds in accordance with the terms adopted in the State plan.[5] Currently, the

---

[3]While weatherization activities are an authorized use of LIHEAP funds, some restrictions apply. Unless a state obtains a waiver, not more than 15% of LIHEAP funds available in a given year may be used for weatherization. 42 U.S.C.A. § 8624(k)(1). In order to obtain a waiver to use up to 25% of LIHEAP funds for weatherization, a state must demonstrate, among other things, that the additional expenditure on weatherization will not reduce the number of households benefitting from the fuel assistance and crisis assistance components. 42 U.S.C.A. § 8624(k)(2).

[4]*See* 42 U.S.C.A. § 8624(b)(1)(C) (as part of state's annual application for allotment of LIHEAP funds, state's chief executive officer shall certify that state will "provide low-cost residential weatherization and other cost-effective energy-related home repair").

[5]*See* 42 U.S.C.A. § 8624(d). The federal government, in making grants of LIHEAP funds to the states to assist low-income households in meeting their immediate home energy needs, permits each state to allocate those funds among certain specified components to

"(A) conduct outreach activities and provide assistance to low income households in meeting their home energy costs, particularly those with the lowest incomes that pay a high proportion of household income for home energy ...;

"(B) intervene in energy crisis situations;

"(C) provide low-cost residential weatherization and other cost-effective energy-related home repair; and

"(D) plan, develop, and administer the State's program[.]" 42 U.S.C.A. § 8624(b)(1).

VEAP regulations and the State plan provide for the allocation of LIHEAP funds between fuel assistance and crisis assistance, and neither includes a weatherization component.[6] Accordingly, it is my opinion that the Board may not authorize or permit the expenditure of LIHEAP funds for weatherization services, such as those provided by WAP, unless those services fall within either the fuel assistance component or crisis assistance component.[7]

You next ask whether the Board must comply with the requirements of the APA to amend its VEAP regulations. The APA governs the promulgation of regulations and the issuing of case decisions by agencies of the Commonwealth.[8] The APA provides for extensive notice and public comment procedures prior to the enactment and revision of regulations.[9] While certain agency actions relating to grants of federal funds are exempted from the requirements of the APA,[10] the promulgation and amendment of regulations for public assistance programs do not fall within this exemption.[11] LIHEAP is a public assistance program for purposes of the APA.[12] It is well-settled that "[i]f the language of a statute is plain and unambiguous, and its meaning perfectly clear and definite, effect must be given to it."[13] It is unnecessary to resort to any rules of statutory construction when the language of a statute is unambiguous.[14] In those situations, the plain meaning and intent of the statute govern. Accordingly, it is my opinion that the Board is required to comply with the APA in order to amend its VEAP regulations.

---

Federal law imposes certain procedural restrictions pertaining to public notice and comment on each state's yearly plan for the use of LIHEAP funds by requiring that "[n]o funds shall be allotted to such State for any fiscal year ... unless such State conducts public hearings with respect to the proposed use and distribution of funds .... 42 U.S.C. § 8624(a)(2). Furthermore, "[e]ach plan ... and each substantial revision thereof shall be made available for public inspection within the State involved in such a manner as will facilitate timely and meaningful review of, and comment upon, such plan or substantial revision." 42 U.S.C. § 8624(c)(2); *see also* § 8624(b)(12) (requiring state's chief executive officer to certify that state agrees to "provide for timely and meaningful public participation in the development of the plan").

[6]*See* 11:2 Va. Regs. Reg. VR 615-08-1, *supra* pts. II-III, at 259-61; State plan, *supra* note 1, at 12-13.

[7]For example, the replacement or repair of heating equipment falls within the crisis assistance component and could be funded without change in the VEAP regulations and the State plan. *See* 11:2 Va. Regs. Reg. VR 615-08-1, *supra* § 3.1(C)(1), (4), at 3146; State plan, *supra* note 1, at 13.

[8]*See* §§ 9-6.14:7.1 to 9-6.14:9.4; §§ 9-6.14:11 to 9-6.14:18.

[9]Section 9-6.14:7.1.

[10]Section 9-6.14:4.1(B)(4).

[11]*See* § 9-6.14:7.1(E), (I) (directing that public assistance programs conform to APA requirements).

[12]*See* § 9-6.14:7.1(J); *see also* § 63.1-87 (definitions of "public assistance," "fuel assistance").

[13]*Temple v. City of Petersburg*, 182 Va. 418, 423, 29 S.E.2d 357, 358 (1944); 1993 Op. Va. Att'y Gen. 256, 257.

[14]*See Ambrogi v. Koontz*, 224 Va. 381, 386, 297 S.E.2d 660, 662 (1982); 1993 Op. Va. Att'y Gen. 99, 100.

Your final question is whether LIHEAP funds may be allocated to WAP by executive order of the Governor.[15] Prior opinions of the Attorney General discuss the authority of a Governor to issue executive orders and the appropriate context for executive orders:

> Although no provision of the Constitution explicitly authorizes the Governor to issue executive orders and no Virginia statute provides a general grant of authority to issue such orders, Governors of the Commonwealth have historically issued executive orders in the absence of a specific statute expressly or generally conferring the authority. The Governor has the inherent authority to issue executive orders in order to 'take care that the laws be faithfully executed.' It is recognized that there is a general reservoir of powers granted by the Constitution to the Governor as the Chief Executive of the Commonwealth.[16]

These prior opinions of the Attorney General conclude that the use of executive orders is appropriate

> (1) Whenever a provision of the Code of Virginia expressly confers that authority upon the Governor;
>
> (2) Whenever there is a genuine emergency which requires the Governor, pursuant to his constitutional responsibility and power, to issue an order, to abate a danger to the public regardless of the absence of explicit authority; and
>
> (3) Whenever the order is administrative in nature, as opposed to legislative.
>
> An executive order may not, however, be employed when a law is required.[17]

This is because the legislative power of the Commonwealth is vested in the General Assembly pursuant to Article IV, § 1 of the Constitution of Virginia (1971).[18]

The General Assembly has not expressly authorized the Governor to order such an allocation of LIHEAP funds to WAP. The Governor would not be acting in response to an emergency when the proposed transfer of funds is from LIHEAP activity (immediate assistance with heating emergencies) to

---

[15]"The chief executive power of the Commonwealth shall be vested in a Governor." VA. CONST. art. V, § 1 (1971). When a Governor may properly issue an executive order has been the subject of much debate. *See, e.g.*, Note, *Gubernatorial Executive Orders as Devices for Administrative Direction and Control*, 50 IOWA L. REV. 78 (1964); *see also*, 2 A.E. DICK HOWARD, COMMENTARIES ON THE CONSTITUTION OF VIRGINIA 587-90 (1974).

[16]1983-1984 Op. Va. Att'y Gen. 180, 182 (quoting Art. V, § 7 ) *quoted in* 1990 Op. Va. Att'y Gen. 1, 3; *see also* 1945-1946 Op. Va. Att'y Gen 144.

[17]1983-1984 Op. Va. Att'y Gen. *supra*, at 182-83, *quoted in* 1990 Op. Va. Att'y Gen., *supra*.

[18]*Accord Youngstown Sheet & Tube Co. v. Sawyer*, 343 U.S. 579, 587 (1952) (federal constitution limits presidential power in lawmaking process; all legislative powers are vested in Congress).

WAP activity (reduction of energy costs over the long-term through weatherization services). While the allocation of funds may appear to be administrative in nature, federal law requires certain procedural requirements for the expenditure of the funds, which cannot be superseded by executive order. It is, therefore, my opinion that the allocation of LIHEAP funds to WAP is not an appropriate subject matter for the Governor to consider in issuing an executive order. Accordingly, allocation of LIHEAP funds to WAP may not be accomplished by means of an executive order.

With kindest regards, I am

Very truly yours,

James S. Gilmore, III
Attorney General

6:HU/54-313

# VIRGINIA ACTS OF ASSEMBLY —CHAPTER

*An Act to require the Department of Social Services, or any other agency succeeding in pertinent authority, to allocate federal low-income fuel assistance program funding to low-income weatherization assistance programs.*

[H 675]

Approved

Whereas, the Low Income Home Energy Assistance Program (LIHEAP), a federally funded program administered by the Department of Social Services (DSS), provides short-term home heating fuel assistance to low-income individuals; and

Whereas, during program year 1994-1995 DSS paid out more than $21 million in LIHEAP benefits, and the average benefit paid per household was $181; and

Whereas, the Weatherization Assistance Program (WAP), administered by the Department of Housing and Community Development (HCD) and principally funded by the U.S. Department of Energy, is designed to reduce the energy costs of low-income households by weatherizing homes and providing essential repairs to heating systems; and

Whereas, WAP's statewide budget in 1994-1995 was $4.7 million, and a budget of $3.5 million is projected in 1995-1996 due to declining federal funding for WAP; and

Whereas, for the past two years general fund appropriations have been necessary to keep the program operational statewide—a condition necessary to qualify for federal funding; and

Whereas, WAP and LIHEAP should be better coordinated to ensure that individuals and families eligible for fuel assistance benefits have weatherized homes and heating systems in good repair to help reduce each home's heating costs while freeing up fuel assistance dollars for other eligible program participants; and

Whereas, Federal LIHEAP regulations permit up to 15 percent of states' LIHEAP grants to be spent on weatherization, and an additional 10 percent may be spent on weatherization upon application to and approval by the program's federal administrators; now, therefore,

**Be it enacted by the General Assembly of Virginia:**

**1.** *§1. That the Department of Social Services, or any other agency succeeding in pertinent authority, is directed to allocate at least 7.5 percent of all federal low-income fuel assistance program funding made available to the Commonwealth to low-income weatherization assistance programs, to the extent such allocation is permitted by federal law.*

EUGENE M. TRISKO
ATTORNEY AT LAW*
P.O. BOX 596
BERKELEY SPRINGS, WV 25411

(304) 258-1977
FAX (304) 258-3927
*ADMITTED IN DC ONLY

# A Case Study of Regulatory Excess:

# Ozone Transport Commission

# and

# Proposed 32-State "Beyond Reasonably Available Control Technology"

# with

# Proposed Model State Legislation[1]

**Presented at:**

**Virginia Coal & Energy Commission**
**Blacksburg, Virginia**
**August 30, 1995**

---

[1]For further information or assistance, please contact the author or the Center for Energy & Economic Development, Inc., at its regional offices: John Paul (East/Northeast) at 609 383-0066; Randy Eminger (South/Texas) at 806 359-5520; or Rosemary Wilson (Midwest/North Central) at 314 342-3477.

BEYOND RACT: REGULATORY EXCESS!

- WE ALL KNOW THIS: THE NORTHEAST OZONE TRANSPORT COMMISSION HAS PROPOSED CALIFORNIA ELECTRIC VEHICLE AND AUTO EMISSION MANDATES FOR THE 12 NORTHEAST STATES

- MOST DON'T KNOW THIS: AN OTC "MEMORANDUM OF UNDERSTANDING" (MOU) REQUIRES STATIONARY SOURCE NOx EMISSION REDUCTIONS OF 75% BY 2003, FAR IN EXCESS OF STATE-DETERMINED "REASONABLY AVAILABLE CONTROL TECHNOLOGY" REQUIRED BY THE CLEAN AIR ACT, AND BEFORE THE 2005-07 CLEAN AIR DEADLINES FOR SEVERE NONATTAINMENT AREAS

- THE MOU WILL COST UTILITY RATEPAYERS IN THE NORTHEAST $22 BILLION OVER THE NEXT 15 YEARS, RAISING ELECTRIC RATES IN A REGION WITH SOME OF THE HIGHEST RATES IN THE NATION

- ACCORDING TO EPA COMPUTER MODELS, NEITHER THE PROPOSED AUTO STANDARDS NOR THE MOU WILL BRING THE NORTHEAST INTO ATTAINMENT WITH AMBIENT OZONE STANDARDS

- ACCORDING TO ACTUAL AIR QUALITY MONITORS, MOST AREAS OF THE COUNTRY WILL ATTAIN THE OZONE STANDARDS DUE TO COMPLIANCE WITH THE 1990 CLEAN AIR ACT

- MEANWHILE, EPA IS FUNDING A $60 MILLION RESEARCH PROJECT TO STUDY HOW OZONE IS FORMED AND TRANSPORTED - BUT THE RESULTS WON'T BE AVAILABLE BEFORE STATES MUST PROCEED WITH RULEMAKING UNDER THE MOU

- EPA HAS THREATENED 32 STATES EAST OF AND BORDERING THE MISSISSIPPI WITH LITIGATION IF THEY DON'T "VOLUNTARILY" REDUCE INDUSTRIAL EMISSIONS SIMILAR TO THE OTC MOU

- A FAST-TRACK PROCESS COORDINATED BY EPA MAY RESULT IN "BEYOND RACT" EMISSION CONTROLS FOR THE 32 STATES BY LATE-1996, WITH AN EMISSIONS "CAP AND TRADE" PROGRAM SIMILAR TO THE ACID RAIN PROGRAM AUTHORIZED BY CONGRESS IN 1990

- STATES WOULD BE EXPECTED TO SIGN ON TO ENFORCEABLE EMISSION REDUCTION COMMITMENTS IN LATE 1996

- CONGRESS DID NOT AUTHORIZE A 32 STATE OZONE "CAP AND TRADE" PROGRAM! IT DID NOT CONTEMPLATE "BEYOND RACT" CONTROLS FOR POWERPLANTS OUTSIDE THE NORTHEAST!

- EMISSION "OFFSET" REQUIREMENTS FOR NEW SOURCES WOULD HAMPER ECONOMIC GROWTH IN THE 32 STATES - BUT NOT IN THE OTHER 18

- THE COST OF BEYOND RACT CONTROLS IN 32 STATES IS LIKELY TO EXCEED $5 BILLION ANNUALLY - COUNTING JUST DIRECT UTILITY COSTS

- EPA'S COMPUTER MODELS PREDICT THAT THESE $5 BILLION OF ANNUAL COSTS WOULD REDUCE OZONE IN THE NORTHEAST BY MERELY 6 TO 9 PARTS PER BILLION A FEW DAYS OF THE YEAR!

- SOME AREAS WOULD EXPERIENCE HIGHER SMOG LEVELS BECAUSE NITROGEN OXIDE EMISSIONS "SCAVENGE" OZONE

- MUCH LARGER AIR QUALITY BENEFITS WILL RESULT FROM COMPLIANCE WITH THE 1990 CLEAN AIR ACT:

  VEHICLE TURNOVER
  CLEANER GAS (IT REALLY WORKS!)
  RACT CONTROLS FOR POWERPLANTS
  ACID RAIN CONTROLS

- STATE LEGISLATURES MUST OVERSEE THE DEVELOPMENT OF THE 32-STATE OZONE TRANSPORT NEGOTIATION

- LEGISLATION IS NEEDED NOW IN ALL 32 STATES TO ENSURE PRIOR LEGISLATIVE REVIEW AND APPROVAL OF ANY "VOLUNTARY" OZONE AGREEMENT SIMILAR TO THE OTC'S MEMORANDUM OF UNDERSTANDING

- MORE TIME IS NEEDED TO PERMIT ONGOING SCIENTIFIC RESEARCH SUCH AS THE $60 MILLION NARSTO PROJECT TO INFORM PUBLIC POLICY

- STATE LEGISLATION SHOULD ENSURE THOROUGH STUDY OF THE ECONOMIC IMPACTS OF INTERSTATE OZONE AGREEMENTS BEFORE STATE EPA'S ARE AUTHORIZED TO SIGN ON

  EMPLOYMENT IMPACTS
  ECONOMIC DEVELOPMENT CONSTRAINTS
  HIGHER UTILITY RATES (RATEPAYERS VOTE TOO!)
  COMPETITIVENESS/REGIONAL CONFLICTS
  RISK OF "STRANDED UTILITY ASSETS"

- STATE LEADERSHIP MUST COMMUNICATE TO MEMBERS OF CONGRESS ITS OPPOSITION TO "BEYOND RACT" AND UNAUTHORIZED REGIONAL "CAP AND TRADE" PROGRAMS INVENTED BY EPA BUREAUCRATS

- DON'T REPEAT THE MISTAKE OF ACID RAIN RESEARCH: LET THE SCIENCE WORK BEFORE ENACTING REGULATIONS!

# COMMONWEALTH of VIRGINIA

*COAL AND ENERGY COMMISSION*
General Assembly Building

910 CAPITOL STREET
SECOND FLOOR
RICHMOND, VIRGINIA 23219

IN RESPONSE TO
THIS LETTER TELEPHONE
(804) 786-3591

October 12, 1995

The Honorable John Warner
The United States Senate
225 Russell Building
Washington, DC 20510

**RE: Ozone Transport Assessment Group (OTAG)**

Dear Senator Warner:

I am writing to you on behalf of the Virginia Coal and Energy Commission to express the Commission's concern about activities of the Ozone Transport Assessment Group (OTAG). As you may know, OTAG operates under the auspices of the federal Environmental Protection Agency (EPA). Its work consists of assessing ozone transport, or movement over the eastern U.S. and the development of national, regional and local ozone control strategies.

OTAG's genesis is in the Northeast Ozone Transport Commission (OTC) which was created by the 1990 federal Clean Air Act Amendments. The OTC, consisting of twelve Northeastern states, was created by Congress and tasked with seeking means of reducing urban ozone and resulting smog. The Clean Air Act, as amended in 1990, establishes federal ozone standards. Areas violating them are subject to stringent pollution control measures, such as enhanced motor vehicle emissions inspections as well as emissions offset requirements for industry. The 1990 Clean Air Act also requires utilities (coal-fired and otherwise) to reduce nitrogen oxide (NOx) emissions. These emissions reductions are subject to "reasonably available control technology), or RACT.

Our concern stems from suggestions that these critical ozone transport issues are being reviewed by OTAG under threat of litigation by the EPA (under Sections 110 and 126 of the federal Clean Air Act). The Commission has been advised that OTAG's objective is a 32-state compact (which would include Virginia) establishing NOx emissions standards that (i) will exceed the emissions control standards imposed by the 1990 Clean Air Act Amendments (ii) will cost utilities and others billions of dollars--over and above compliance costs associated with the 1990 amendments (iii) are based on questionable scientific assumptions, and (iv) *most importantly,* may have negligible effects vis-à-vis reducing air pollution in proportion to their extraordinary cost and detrimental impact on states' economies.

The Virginia Coal and Energy Commission supports the 1990 Clean Air Act Amendments' objectives and goals. However, we also support those who believe that the Act's provisions should be given an opportunity to work before adopting expensive emissions standards exceeding those now provided by federal statute.

On behalf of the Virginia Coal and Energy Commission, I urge you and your colleagues to support emissions control standards expressed in the 1990 Clean Air Act Amendments, and to take all necessary action to ensure that any further modifications to these critical standards are made solely by you and the other members of Congress.

Thank you for giving this issue your attention and consideration.

Sincerely,

Frank W. Nolen/cgf

Frank W. Nolen
Chairman
Member, Senate of Virginia

BOB GOODLATTE
6TH DISTRICT, VIRGINIA

123 CANNON HOUSE OFFICE BUILDING
WASHINGTON, DC 20515-4606
(202) 225-5431
FAX (202) 225-9681

COMMITTEE ON THE JUDICIARY

COMMITTEE ON AGRICULTURE

ASSISTANT MAJORITY WHIP

# Congress of the United States
## House of Representatives

December 27, 1995

The Honorable Frank W. Nolen
Chairman
Virginia Coal and Energy Commission
910 Capitol Street
Second Floor
Richmond, Virginia 23219

Dear Frank:

Enclosed herewith please find a letter dated December 8 which I have received from the Environmental Protection Agency regarding your concerns about the activities of the Ozone Transport Assessment Group (OTAG).

I hope this information will be helpful to you.

A member of my Washington office is looking into your concerns about further modifications to emission control standards. I will be back in touch with you regarding this matter as soon as possible.

In the meantime, if I may be of further assistance to you, please do not hesitate to contact me.

With kind regards.

Very truly yours,

BG

Bob Goodlatte
Member of Congress

RWG:pl

Enclosure

2 SOUTH MAIN STREET
SUITE A, FIRST FLOOR
HARRISONBURG, VA 22801-3707
(540) 432-2391
FAX (540) 432-6593

318 MAIN STREET
SUITE 300
LYNCHBURG, VA 24504-1608
(804) 845-8306
FAX (804) 845-8245

X 540 CRESTAR PLAZA
10 FRANKLIN ROAD, S.E.
ROANOKE, VA 24011-2121
(540) 857-2672
FAX (540) 857-2675

114 NORTH CENTRAL AVENUE
STAUNTON, VA 24401-3307
(540) 885-3861
FAX (540) 885-3930

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

Honorable Bob Goodlatte
House of Representatives
540 Crestar Plaza
10 Franklin Road, S.E.
Roanoke, Virginia 24011-2121

Dear Congressman Goodlatte:

This is in response to your October 30, 1995 letter regarding the activities of the Ozone Transport Assessment Group (OTAG). I would like to take this opportunity to provide you with some background about OTAG and the work that is being done, and to address the specific issues raised by the Chairman of the Virginia Coal and Energy Commission, Mr. Frank Nolen.

A number of areas, primarily in the Northeast and Midwest, have for many years experienced high ozone levels due to transport of pollutants from more severely polluted areas upwind (e.g., Maine is affected by New York). In addition, some nonattainment areas are affected by ozone and ozone precursors transported from areas that are currently designated attainment (e.g., the Northeast is affected by emissions from the Ohio Valley). Because of the transport of these pollutants, actions by the State and local governments to reduce air pollution in the areas themselves may be insufficient to attain the standards. The Clean Air Act (Act), as amended in 1990, recognized the problem of transport in the Northeast and established the Ozone Transport Region (OTR) and the Ozone Transport Commission (OTC) to address the problem. Over the last 5 years, it has become apparent that transport occurs over a much larger area and, in order for States to be able to attain Federal ozone standards, regional reductions in ozone precursors will be necessary.

At the request of the Environmental Council of the States (ECOS), the Environmental Protection Agency (EPA) began to look at ways of providing flexibility within the context of the Act to address the issue of broad-scale transport. On March 2, 1995, EPA issued guidance to help ensure that regional, as well as local, contributions to ozone pollution are addressed effectively. This guidance gave States the option of using a two-phased approach to develop ozone attainment plans. The initial phase I submission would include modeling and a core set of control measures to achieve significant emission reductions in the near term. In phase II, States would also participate in a multistate consultative process to reach consensus on broad regional control strategies and additional local strategies needed to achieve the ozone standard. As a result of this guidance, ECOS established OTAG.

The OTAG is chaired by Mary Gade, Director of the Illinois Environmental Protection Agency, and includes representatives of more than 20 States as well as EPA, industry and environmental groups. Recognizing that no individual State can fully assess or resolve all of the issues related to ozone transport, OTAG brings together States and other relevant stakeholders for a thoughtful assessment and development of consensus solutions to the problem of transport.

The remainder of this letter addresses the specific issues raised by Mr. Nolen.

**Critical ozone transport issues are being reviewed by OTAG under threat of litigation by EPA.** Although there has been some discussion with the States as to how EPA would help put into place any recommendations made by OTAG, the EPA has not threatened litigation to force States to review these issues. As discussed above, it was at the States' request that EPA developed an alternative approach to ozone planning and that OTAG was established. Although EPA is providing technical and financial support, OTAG is a State-run entity.

**OTAG's objective is a 32-State compact establishing NOx emission standards that will exceed the emissions control standards imposed by the Clean Air Act.** The OTAG's objective is to reach consensus on the level of regional nitrogen oxide (NOx) and/or volatile organic compounds (VOC) reductions needed for areas throughout the Eastern United States to meet the requirement of the Act to demonstrate attainment of the ozone standard. While this may result in a recommendation for NOx and VOC reductions greater than what is explicitly required by the Act, it would be consistent with the requirement that States impose requirements necessary to prevent interference with any other State's ability to attain the ozone standard.

**These reductions will cost utilities and others billions of dollars--over and above compliance costs associated with the 1990 amendments.** If OTAG recommends additional controls on utilities, it would only be after careful consideration of the costs, compared to the costs of other alternatives. The OTAG is committed to evaluating a variety of control measures and their associated costs. It is the intent of OTAG to provide a more cost-effective means of attaining the ozone standard throughout the Eastern United States than would be achieved by each State addressing the problem individually.

**The reductions are based on questionable scientific assumptions.** Unfortunately, Mr. Nolen's letter is not specific about these questionable assumptions. The OTAG is committed to using the best science available, including information from the National Academy of Sciences on effectiveness of controls, in the time frame allowed. In addition, the participation in this process of a wide range of stakeholders ensures that any assumptions made will be thoroughly scrutinized.

**The reductions may have negligible effects vis-à-vis reducing air pollution in proportion to their extraordinary cost and detrimental impact on States' economies.** In evaluating any potential control measures, OTAG will be taking into consideration the effectiveness of the measures on reducing ozone. One of the key points to keep in mind is that if regional reductions are not achieved, an even greater burden will be placed on nonattainment areas to find emission reductions.

I appreciate this opportunity to be of service to you and trust that this information will be helpful to you.

Sincerely,

for John S. Seitz
Director
Office of Air Quality Planning
and Standards

Model State Legislation: Interstate Ozone Transport Oversight

A BILL

IN THE (HOUSE/SENATE)

OF THE STATE OF __________

Summary

A bill requiring prior legislative review and approval of any proposed interstate agreement related to the transport of ozone, where such agreement contains stationary source emission control requirements exceeding Reasonably Available Control Technology, as provided by applicable law, or the nitrogen oxide emission limitations required by Section 407 of Title IV of the Clean Air Act Amendments of 1990, 42 U.S.C. 7651f. Requiring certain studies of the economic, employment, and competitive impacts of any proposed interstate agreement related to the transport of ozone.

SHORT TITLE

This Act may be referred to as the Interstate Ozone Transport Oversight Act.

Section 1. The (House/Senate) of the State of __________ hereby finds that:

(a) The Clean Air Act Amendments of 1990 contain a comprehensive regulatory scheme for the control of emissions from mobile and stationary sources, which will improve ambient air quality and health and welfare in all parts of the nation.

(b) The number of areas failing to meet national ambient air quality standards for ozone has been declining steadily and will continue to decline with implementation of the Clean Air Act Amendments of 1990.

(c) Scientific research on the transport of ozone across state boundaries is proceeding under the auspices of the United States Environmental Protection Agency ("EPA"), state agencies, and private entities, which research will lead to improved scientific understanding of the causes and nature of ozone transport, and emission control strategies potentially applicable thereto.

(d) The Ozone Transport Commission established by the Clean Air Act Amendments of 1990 has proposed emission control requirements for stationary and mobile sources in certain northeastern states and the District of Columbia exceeding those mandated by federal law.

(e) The Commonwealth of Virginia and other parties have challenged the constitutionality of the Ozone Transport Commission and its regulatory proposals under the Guarantee, Compact, and Joinder Clauses of the United States Constitution.

(f) The United States EPA, acting under color of federal law, is encouraging states east of and bordering the Mississippi River and Texas to develop and to enter into an interstate agreement on ozone transport requiring reductions of emissions of nitrogen oxides exceeding the requirements of the Clean Air Act Amendments of 1990.

(g) Emission control requirements exceeding those mandated by federal law can adversely affect state economic development, competitiveness, employment, and income without corresponding environmental benefits.

Section 2. Legislative Oversight and Approval; Study Requirements

(a) The (Secretary/Administrator/Director) of the (State) (Department/Agency) of (Environmental Protection or other applicable) shall not, without the prior review and approval by resolution or other act of the (Legislature), enter into any interstate agreement related to the transport of ozone, where such agreement contains stationary source emission control requirements exceeding Reasonably Available Control Technology, as required by applicable law, or the nitrogen oxide emission limitations required by Section 407 of Title IV of the Clean Air Act Amendments of 1990, 42 U.S.C. 7651f.

(b) To assist the review and approval required by the preceding paragraph, the (Department/Division) of (Commerce, Economic Development, PUC/PSC or other appropriate) shall conduct a study of the impacts of any such proposed interstate ozone transport agreement on the State's economy, including, but not limited to, impacts on economic development, employment, income, and industrial competitiveness. Such study shall be submitted to the (Legislature/Committee on ___) not less than ten (10) days prior to any scheduled hearing or other consideration of a proposed interstate agreement related to the transport of ozone.

Section 3. Study of Existing Interstate Ozone Transport Agreements (For states included within the Northeast Ozone Transport Region)

(a) The (Department/Division) of (Commerce, Economic Development, PUC/PSC or other appropriate) shall conduct a study of the impacts of any existing interstate ozone transport agreement on the State's economy, including, but not limited to, impacts on economic development, employment, income, and industrial competitiveness. Such study shall be submitted to the (Legislature/Committee on ___) not less than six (6) months after the date of enactment of this Act. (Note: May extend to similar impacts of proposed automotive emission limitations exceeding federal Tier I auto standards.)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 2 - 1995

OFFICE OF
AIR AND RADIATION

MEMORANDUM

SUBJECT: Ozone Attainment Demonstrations

FROM: Mary D. Nichols
Assistant Administrator for Air and Radiation

TO: Regional Administrator, Regions I-X

The purpose of this memorandum is to provide guidance on an alternative approach to provide States flexibility in their planning efforts for ozone nonattainment areas classified as serious and above. The basic principles of this approach are: 1) meeting the attainment dates in the Clean Air Act while maintaining progress, 2) ensuring enforceability of commitments to adopt additional measures needed to reach attainment, and 3) promoting market-based alternatives. The EPA will work with States to encourage the development of market-based trading programs to provide flexibility in meeting the requirements of these control measures. This guidance applies to areas significantly affected by ozone transport. In consultation with your States, you should determine whether it is appropriate to apply it to other areas as well.

Background

The 1990 Clean Air Act Amendments set forth many new requirements intended to address widespread nonattainment of the NAAQS for ozone. Although a great deal of work has been done and significant progress has been made, many States have been unable to complete these State implementation plan (SIP) requirements within the schedules prescribed in the Act due to circumstances beyond their control. This is a particularly difficult problem for areas affected by transport of ozone and ozone precursors. These areas must develop complex regulatory plans, based on photochemical grid models that in many cases must take into account upwind and downwind flow of ozone and precursors. The models, in turn, must be based on detailed emission inventories and other inputs, the development of which has been unavoidably delayed due to unforeseen difficulties in gathering the necessary data. Similarly, in many instances, the large amount of reductions likely to be needed to demonstrate attainment, and the consequent difficulties in developing control measures to achieve those reductions, has resulted in unavoidable delays in rule development by the States.

This memorandum provides States with an approach for obtaining full approval for their attainment demonstration State implementation plans by implementing a two-phased program. In addition to the other requirements set forth in this memorandum, States must fulfill all ozone nonattainment obligations due to be completed prior to November 1994 (e.g., 15 percent plans, VOC and NOx RACT) before EPA will approve ozone nonattainment plans based on this approach.

Phase I

Under the first phase, States should submit a plan to implement, by May 1999,[1] a set of specific control measures (including at least a 9 percent reduction to satisfy rate-of-progress requirements) to obtain major reductions in ozone precursors. In the Northeast ozone transport region (OTR), the measures should include: 1) all mandatory Clean Air Act measures required prior to November 1994, including: VOC and NOx RACT on major sources, enhanced I/M, reformulated gasoline (where required), rate-of-progress requirements (at least up to 1999), clean fuel fleets; 2) the regional NOx MOU (on the timetable agreed upon by the OTC); 3). LEV or a 49-State car program if one is adopted. The specific control measures required in areas outside the OTR will be determined on a case-by-case basis based on consultation between the States and the appropriate Regional Office(s). For the Lake Michigan States (Illinois, Indiana and Wisconsin) the phase I measures should include all measures necessary to meet the rate-of-progress requirements out to the attainment date (2007). At a minimum, the measures selected for all other areas should be comparable to those in the OTR and Lake Michigan area.

In addition, SIPs should include either modeling with interim assumptions about ozone transport (this modeling might not show attainment) or modeling that shows attainment based on an assumed boundary condition (to be determined in consultation with EPA). Finally, submittals should include an enforceable commitment to 1) participate in a consultative process to address regional transport, 2) adopt additional control measures as necessary to attain the ozone NAAQS, meet rate-of-progress requirements, and eliminate significant contribution to nonattainment downwind, and 3) identify any reductions that are

---

[1] There are two exceptions to this date. The first is where the Act specifies a different date (earlier or later). In this situation, measures should be implemented in accordance with the schedule in the Act. The second case is where States have agreed (e.g., in a memorandum of understanding) to implement specific regional controls according to a scheduled outlined in the MOU. In this case, States should follow the implementation scheduled agreed to in the MOU.

needed from upwind areas for the area to meet the NAAQS. The commitment should also specify a schedule for completing adoption of additional rules. An enforceable commitment is one that has been adopted into the SIP by the State and is submitted to EPA as a SIP revision. The EPA will work with States regarding the specific commitments that are needed.

States should submit, by May 1995, a letter committing to follow the approach described in this guidance, as well as a general explanation of efforts to date to complete both the attainment modeling (and the emission inventory and other inputs to the model) and the regulations necessary to achieve reductions. The letter should include a schedule for the adoption of enforceable rules needed to implement the required phase I control measures.

In order to provide lead time for phased implementation of those measures not later than May 1999, any measures not already scheduled for earlier adoption should be adopted no later than the end of 1995. If administrative scheduling, such as legislative sessions or State review procedures renders it impossible for a control agency to complete the regulatory process for certain rules by the end of 1995, the State may propose a schedule providing for the adoption of such rules during 1996. Again, the important point is that the State must adopt enforceable measures by a date that ensures adequate lead time to enable full implementation no later than May 1999. The Regions should track States' progress toward completion of the adoption process.

Phase II

The second phase of this approach begins with a 2-year process, ending at the close of 1996, to assess regional control strategies and refine local control strategies, using improvements in the modeling process (e.g., more refined emission inventories) to perform further control strategy evaluations that take into consideration potential regional control strategies. This will also give the States and EPA the opportunity to determine appropriate regional strategies to resolve transport issues. The goal of phase II is for EPA and the affected States to reach consensus on the additional regional, local and national emission reductions that are needed for the remaining rate-of-progress requirements and attainment. In the event that agreement is not reached, EPA intends, by the end of 1997, to use its authority under the Act (e.g., under sections 126 and/or 110) to work with all affected States to ensure that the required reductions are achieved.

Based on the results of the 2-year assessment, States will be expected to submit by mid-1997 the modeling and attainment plan to show attainment through local and regional controls. The attainment plan should identify the measures that are needed for rate-of-progress and attainment. The remaining rules needed for serious areas to attain must be adopted and implemented in time for those areas to meet their attainment date of 1999.

For nonattainment areas with later attainment dates, States should adopt and implement local and regional control measures as determined to be necessary to meet the statutory attainment deadlines. States should phase-in adoption of rules to provide for implementation of measures for rate-of-progress beginning in the period immediately following 1999. These rules must be submitted to EPA no later than the end of 1999 (unless they were submitted as part of phase I), and provide for timely implementation of progress requirements.

If you have any questions during implementation of this policy, please contact me or John Seitz, Director of the Office of Air Quality Planning and Standards. The staff contact is Laurel Schultz (919-541-5511).

cc: Air Branch Chief, Regions I-X
Rob Brenner
David Doniger
Alan Eckert
William Hunt
Phil Lorang
Mary Nichols
Rich Ossias
Sally Shaver
Lydia Wegman
Richard Wilson

# OZONE TRANSPORT ASSESSMENT GROUP (OTAG)

Presentation by

Bharat Mathur, Chief
Bureau of Air
Illinois Environmental Protection Agency

To

Virginia Coal & Energy Commission's Energy
Preparedness Subcommittee

October 16, 1995

g:\tap\vircoal

# OZONE TRANSPORT ASSESSMENT GROUP

- Why and how OTAG was formed

  * Many states were unable to submit attainment demonstrations by November 15, 1994, the deadline in the Clean Air Act.

  * Many recognized the of transport as a source of states' inability to demonstrate attainment.

  * USEPA accepted this proposition, as demonstrated by Mary Nichols' March 2, 1995, memorandum.

  * Nichols' memorandum allows states extra time for attainment demonstrations if they complete their Phase I requirements and commit to working together towards a solution of the transport problem.

- OTAG's structure

  * Policy Group: states' environmental commissioners and two USEPA directors

  * Subgroups (2): chaired by states' air directors

  * Workgroups (6): co-chaired by states or regional organization and USEPA staff

- The OTAG project

  * The Inventory Workgroup is compiling the 1990 baseyear and future year inventories and preparing them as modeling inputs.

* The Modeling Workgroup will model the baseyear and future year inventories using control strategies identified by the Implementation Strategies & Issues Workgroup for four episodes: July 1-15, 1988; July 13-21, 1991; July 7-18, 1995; and July 20-30, 1993.

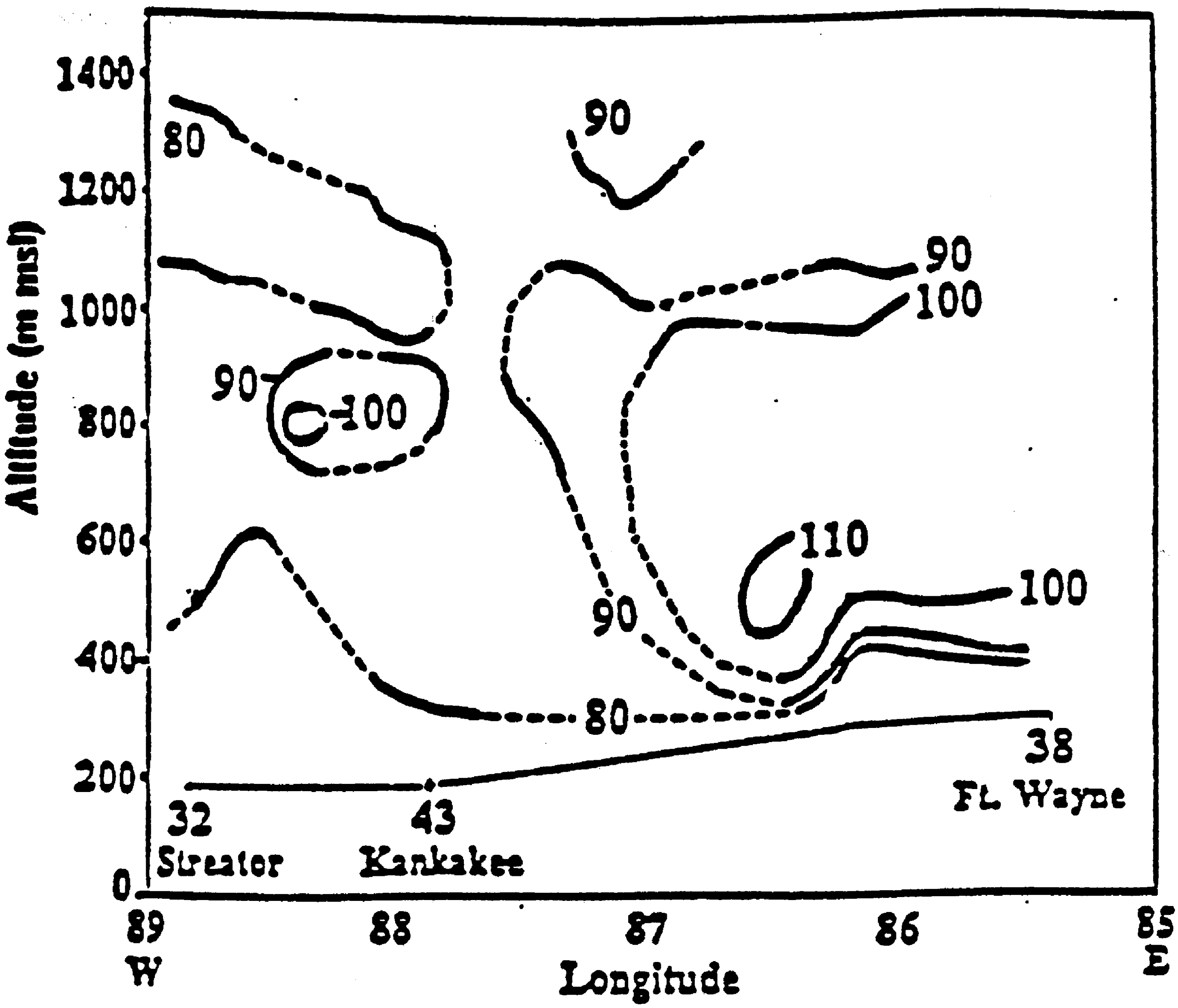
* Meanwhile, the Air Quality Analysis Workgroup is analyzing "real" data obtained from monitoring to verify the modeling results and to ascertain any additional trends and information.

* The Trading/Incentives Workgroup is looking at a trading program. A trading program is not mandated by any statute; however, a trading program is not prohibited, and the Clean Air Act encourages market-based measures. Presently, the Workgroup is considering a trading scheme that accommodates both a cap & trade system and an open market system.

- The OTAG end-product:

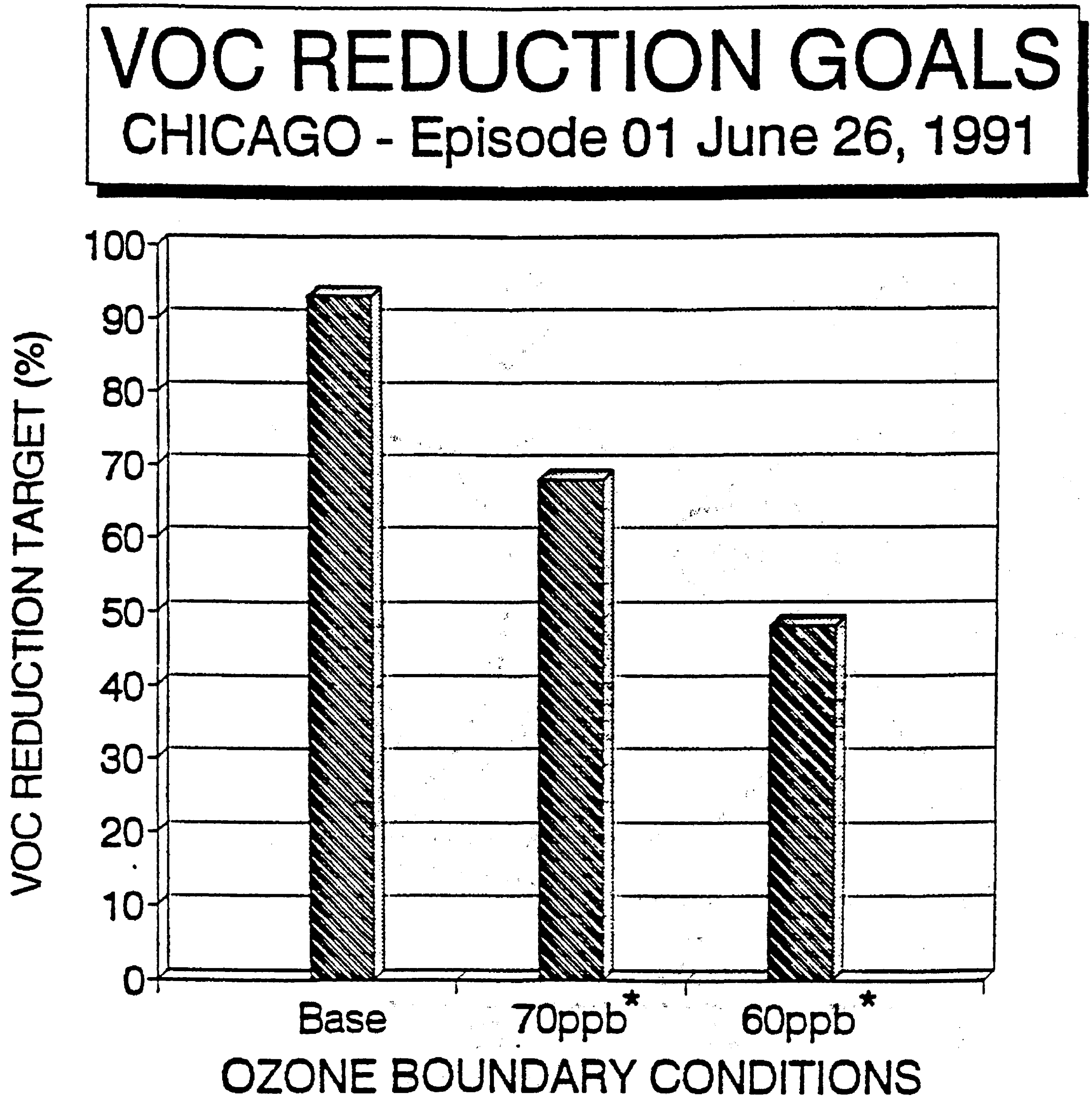
  * Recommendation to USEPA addressing ozone transport

  * No preconceived notions regarding the recommendation



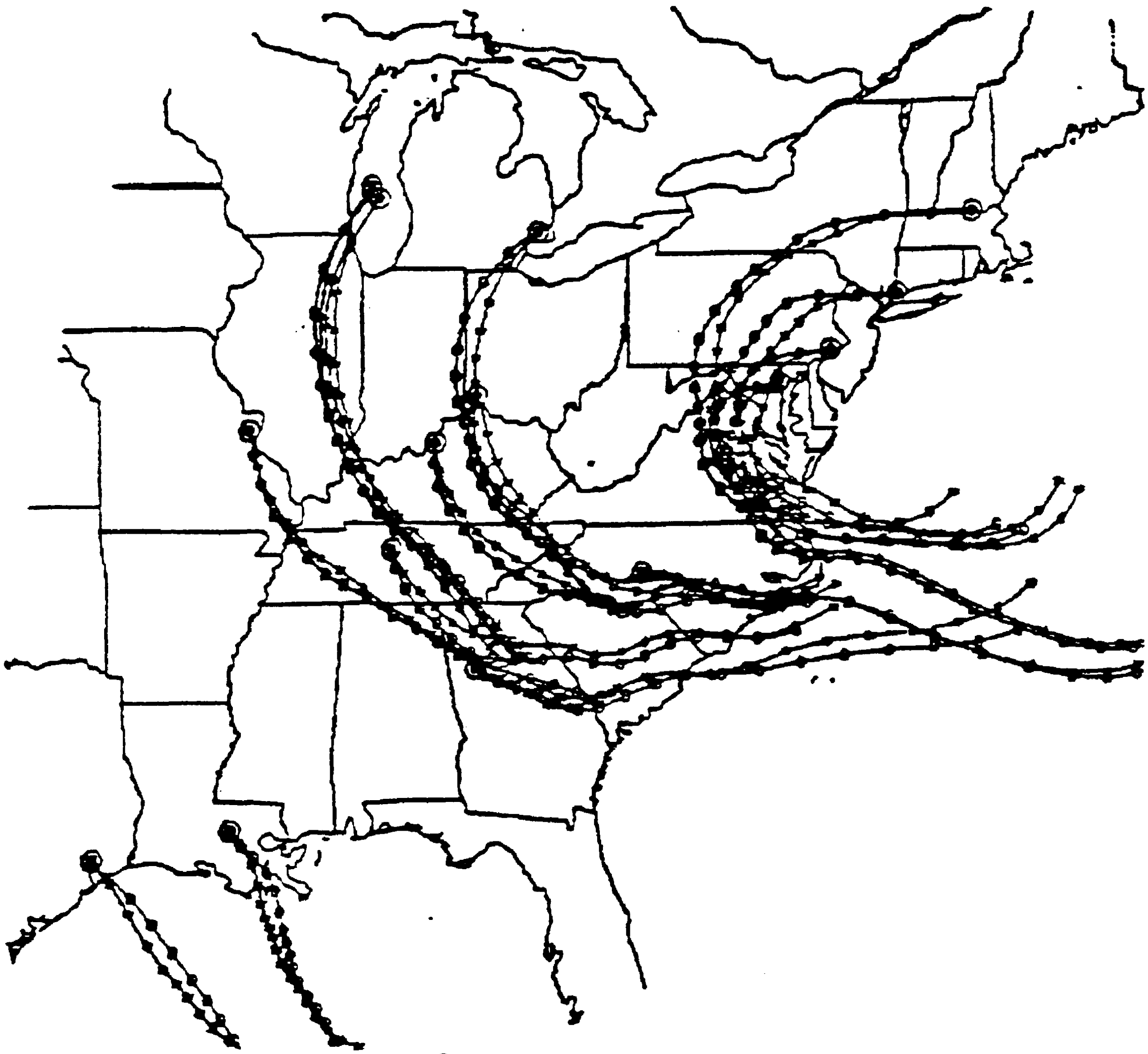

Ozone Concentrations Measured along the Southern LMOS Boundary

July 18, 1991

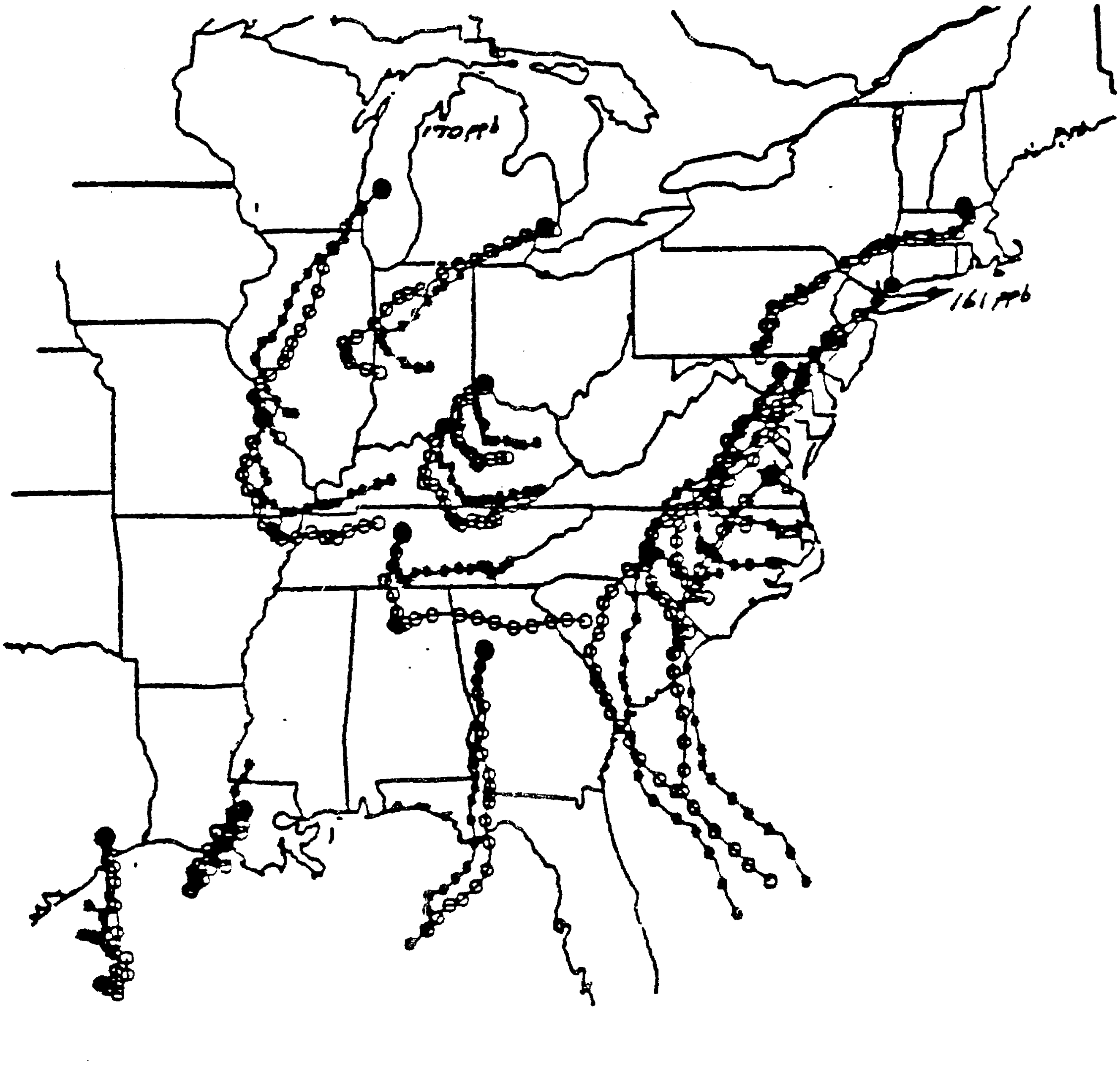



* Assumes a 30% reduction of precursors at the boundary.

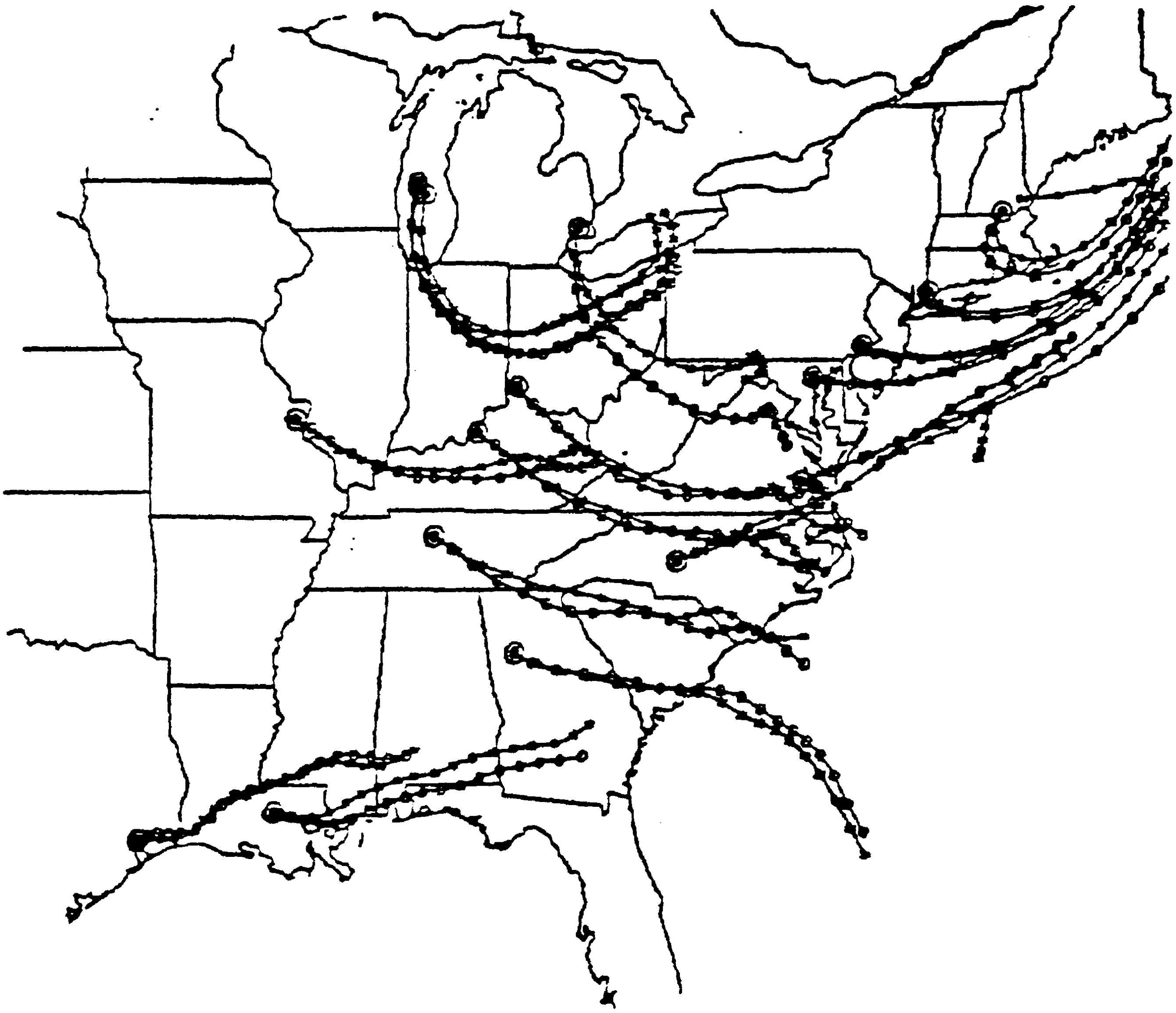
# Episode 1 Trajectory Analysis
## June 25-28, 1991



# Episode 2 Trajectory Analysis
## July 17-19, 1991

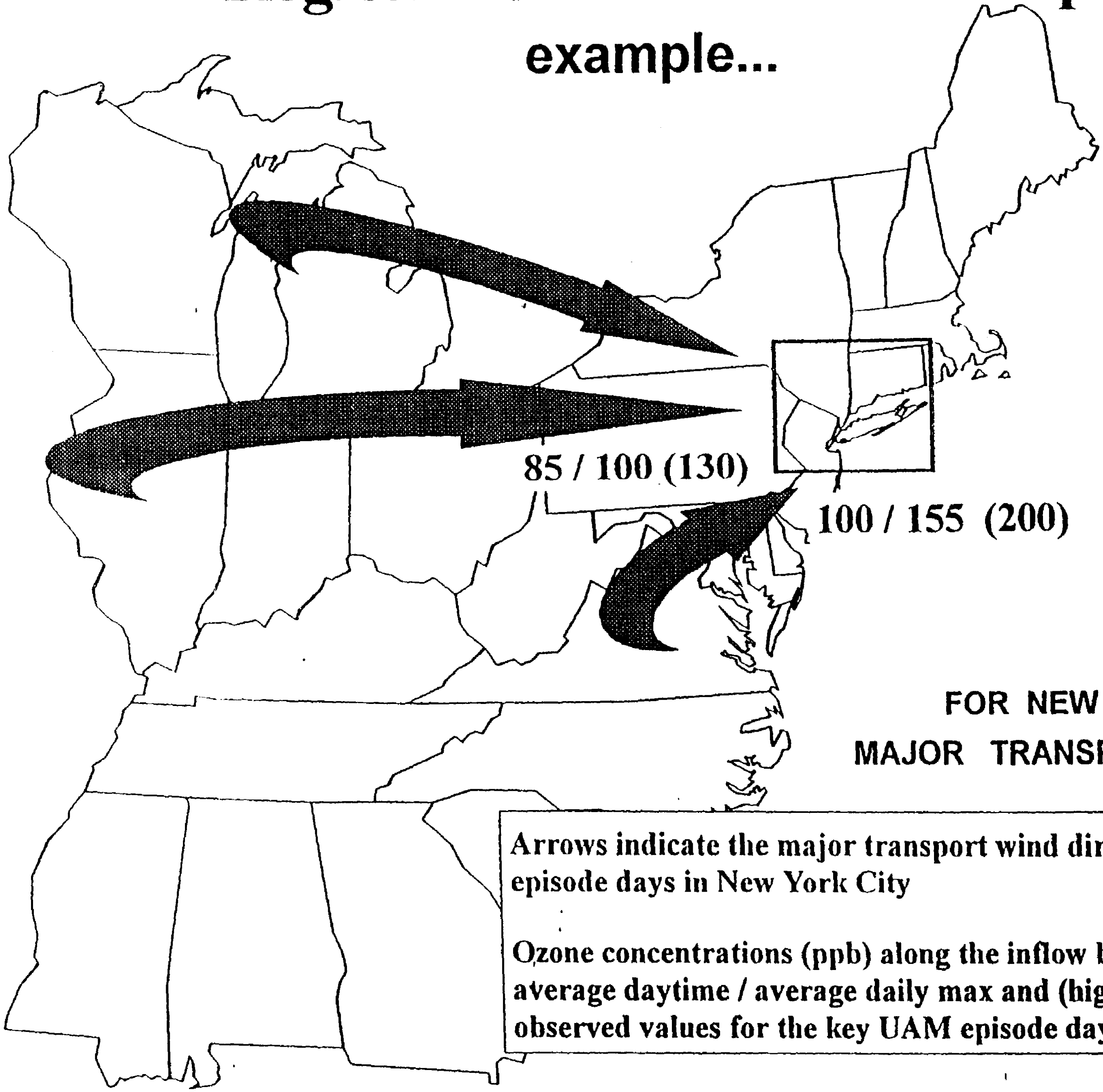


# Episode 3 Trajectory Analysis
# August 23-26, 1991



# Regional Ozone Issue...Transport

## example...



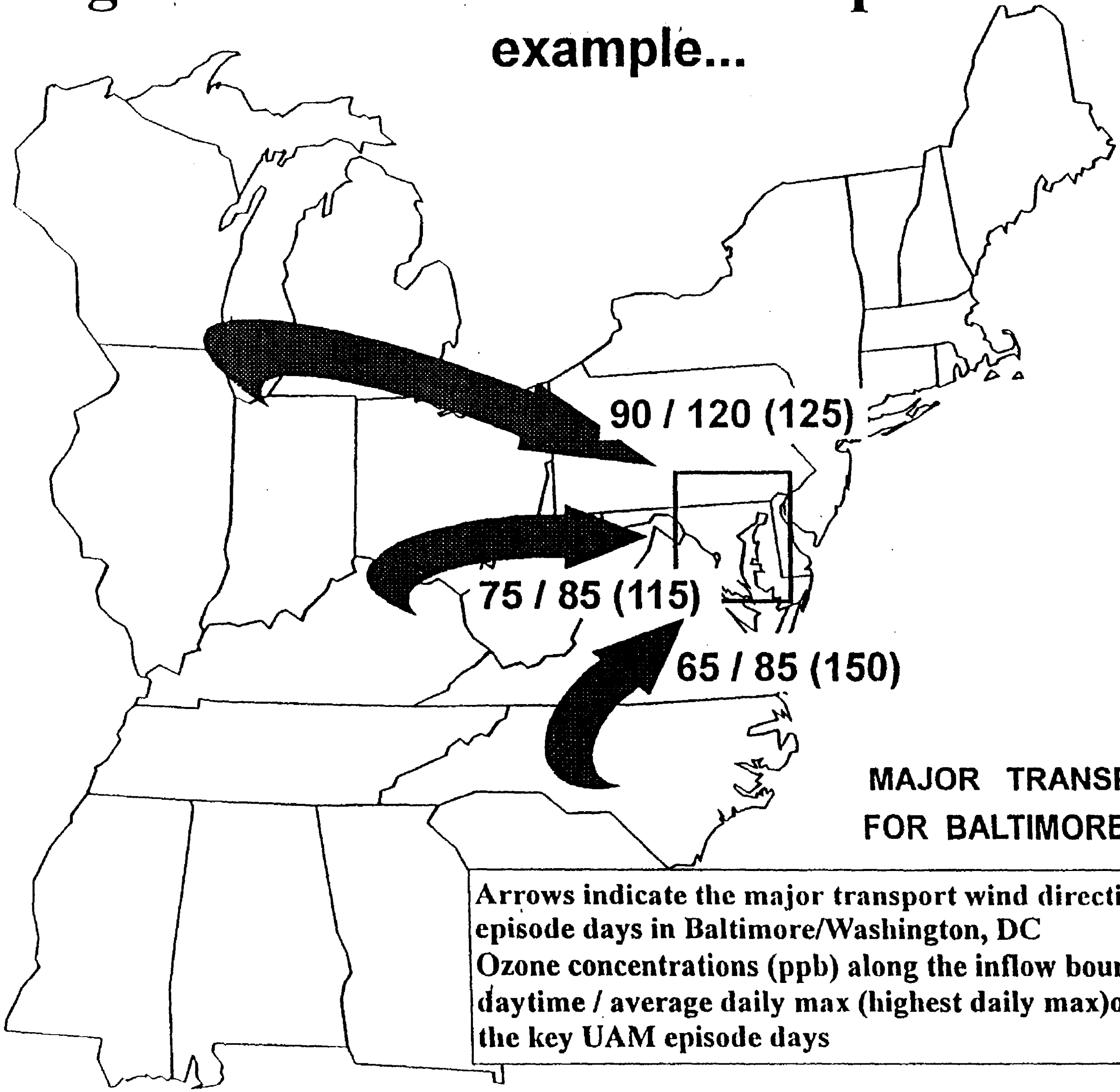

**FOR NEW YORK CITY**
**MAJOR TRANSPORT PATTERNS**

Arrows indicate the major transport wind directions for key UAM episode days in New York City

Ozone concentrations (ppb) along the inflow boundaries are average daytime / average daily max and (highest daily max) observed values for the key UAM episode days

# Regional Ozone Issue...Transport

## example...

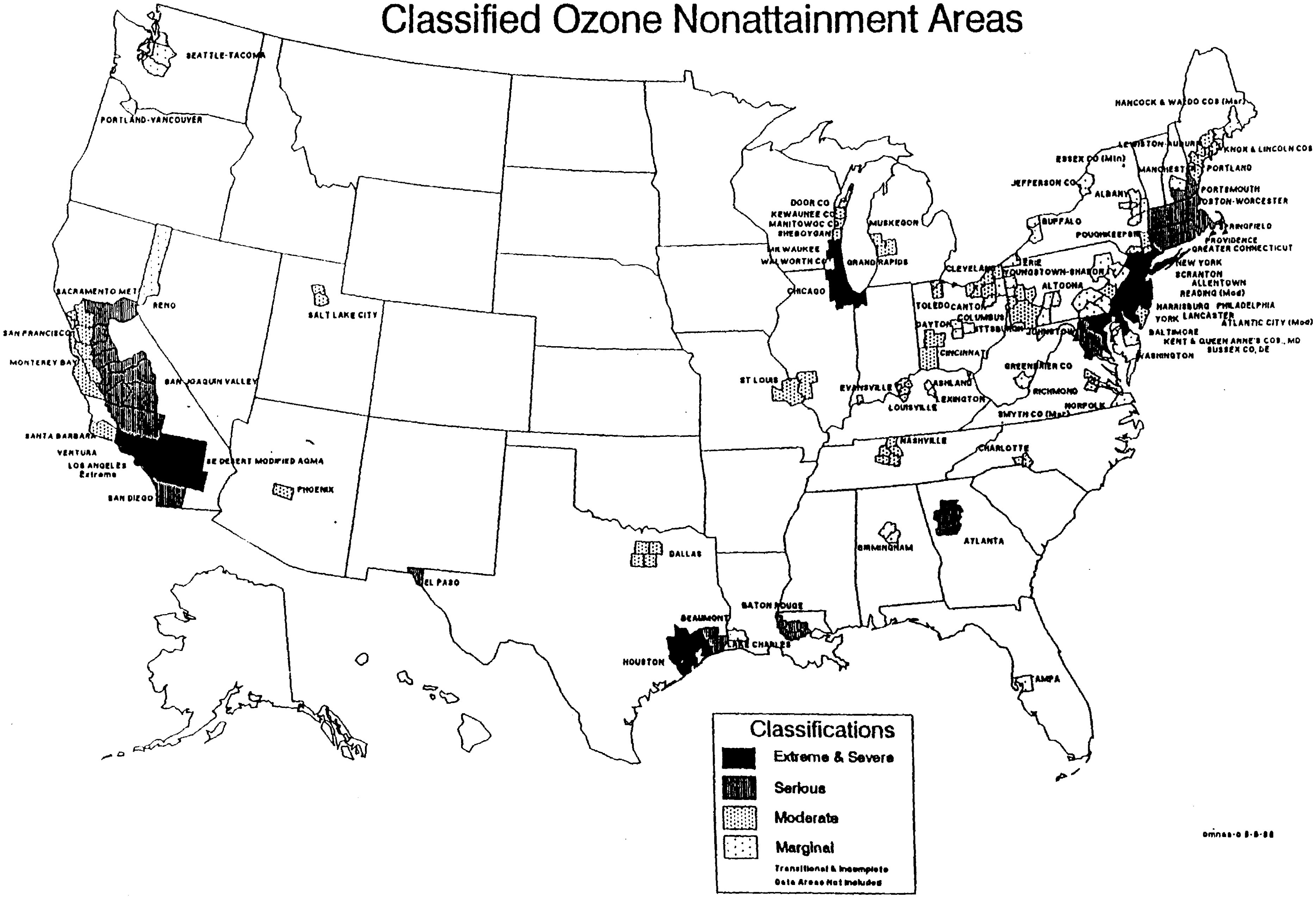



**MAJOR TRANSPORT PATTERNS FOR BALTIMORE/WASHINGTON, DC**

Arrows indicate the major transport wind directions for key UAM episode days in Baltimore/Washington, DC
Ozone concentrations (ppb) along the inflow boundaries are average daytime / average daily max (highest daily max)observed values for the key UAM episode days

# Current Nonattainment Status

## Classified Ozone Nonattainment Areas



## Ozone Attainment Demonstration Policy

- Federal Guidance issued on March 2, 1995

- Basic Principles
    - Meet CAA Attainment dates
    - Ensure enforceability of commitments
    - Promote Market-Based Alternatives

- Full Approval of Attainment Demonstration
    - Implement two-phased program
    - Fulfill all CAA-mandated measures that were due prior to November 1994

- Phase I -- By May 1995, the state is to commit to the following, assuming an initial boundary condition:
    - adopt and implement by 1999 the first three-year ROP measures,
    - adopt by 1999 all measures needed for ROP,
    - participate in the super-regional modeling assessment.

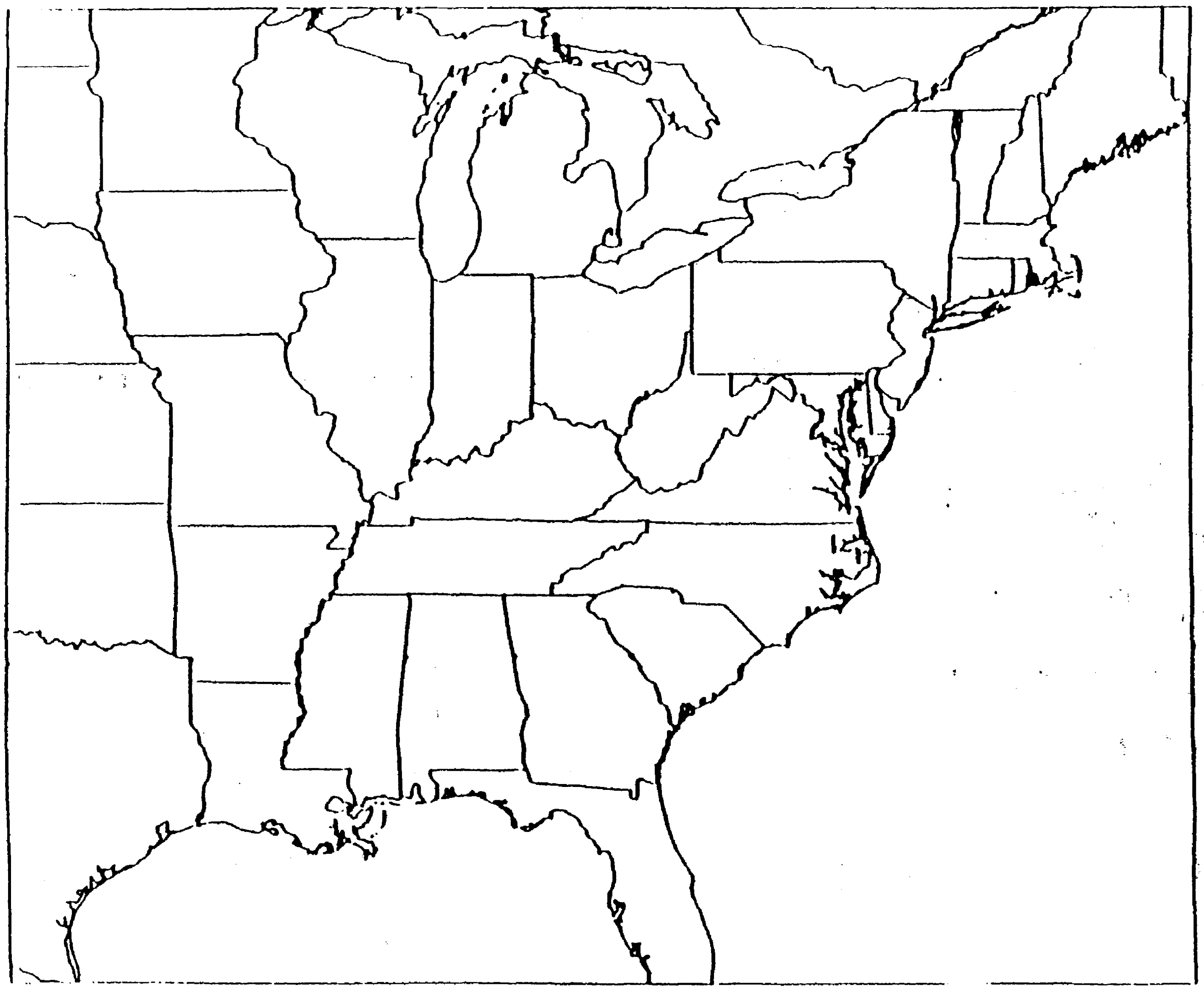
- Phase II -- Goal is for EPA and states to agree on appropriate regional, local, and national emissions reductions based on super-regional modeling assessment.

## STATES PARTICIPATING IN OTAG

Alabama
Arkansas
Connecticut
Delaware
District of Columbia
Florida
Georgia
Kansas
Illinois
Indiana
Iowa
Kentucky
Louisiana
Maine
Maryland
Massachusetts
Michigan
Minnesota
Mississippi
Missouri
Nebraska
New Hampshire
New Jersey
New York
North Carolina
North Dakota
Ohio
Oklahoma
Pennsylvania
Rhode Island
South Carolina
South Dakota
Tennessee
Texas
Vermont
Virginia
West Virginia
Wisconsin

Others are encouraged to join in the OTAG effort.

# Regional Oxidant Model (ROM) -- Super Domain



# OZONE TRANSPORT ASSESSMENT GROUP

## POLICY DECISION GROUP

**Chair - Mary Gade, Illinois**
ECOS Commissioners
John Seitz/Margo Oge, USEPA

## Advisory Panel

**Chair - Bharat Mathur, Illinois**

STAPPA/ALAPCO- Bill Becker
OAQPS- Sally Shaver
OMS - Meredith Miller
Region V - David Kee
New Jersey - John Elston
Ohio - Robert Hodanbosi

## Modeling & Assessment Subgroup

**Chair - New Jersey**
Commissioner, Bob Shinn
Air Director, John Elston

Members: State Air Directors
STAPPA/ALAPCO
Regional Air Organizations
EPA HQ./Regional Offices
Associate: Industry Representatives
Environmental Groups

## Strategy & Controls Subgroup

**Chair - Ohio**
Director, Don Schregardus
Air Director, Robert Hodanbosi

Members: State Air Directors
STAPPA/ALAPCO
Regional Air Organizations
EPA HQ./Regional Offices
Associates: Industry Representatives
Environmental Groups

# OTAG SUBGROUP: MODELING & ASSESSMENT

**Modeling & Assessment Subgroup**

**Chair - New Jersey**
Commissioner, Bob Shinn
Air Director, John Elston

Members: State Air Directors
STAPPA/ALAPCO
Regional Air Organizations
EPA HQ./Regional Offices

Associate: Industry Representatives
Environmental Groups

**Regional & Urban Scale Modeling**

Select the appropriate models for the super-domain modeling.

Mike Koerber, LADCO
Joe Tikvart, EPA

**Emissions Inventory**

Provide the base year emissions inventory and growth factors for modeling.

Roger Randolph, Missouri
David Mobley, EPA

**Air Quality Analysis**

Perform air quality measurements to integrate with modeling.

Bob Collom, SESARM
Dave Guinnup, EPA

# OTAG SUBGROUP: STRATEGY & CONTROLS

**Strategy & Controls Subgroup**

**Chair - Ohio**
Director, Don Schregardus
Air Director, Robert Hodanbosi

Members: State Air Directors
STAPPA/ALAPCO
Regional Air Organizations
EPA HQ./Regional Offices
Associates: Industry Representatives
Environmental Groups

**Control Technologies & Options**

List the CAA Mandatory Control Measures and develop potential future controls

Steve Gerritson, LADCO
Laurel Schultz, EPA

**Implementation Strategies & Issues**

Prepare strategy packages adequate for modeling.

Merrylin Zaw-Mon, Maryland
Bill Baker, EPA

**Trading/Incentives**

Study potential for emissions trading as alternative future control measures.

Jim Rue, Pennsylvania
Doug Grano, EPA

# OTAG PROJECTED GENERAL SCHEDULE

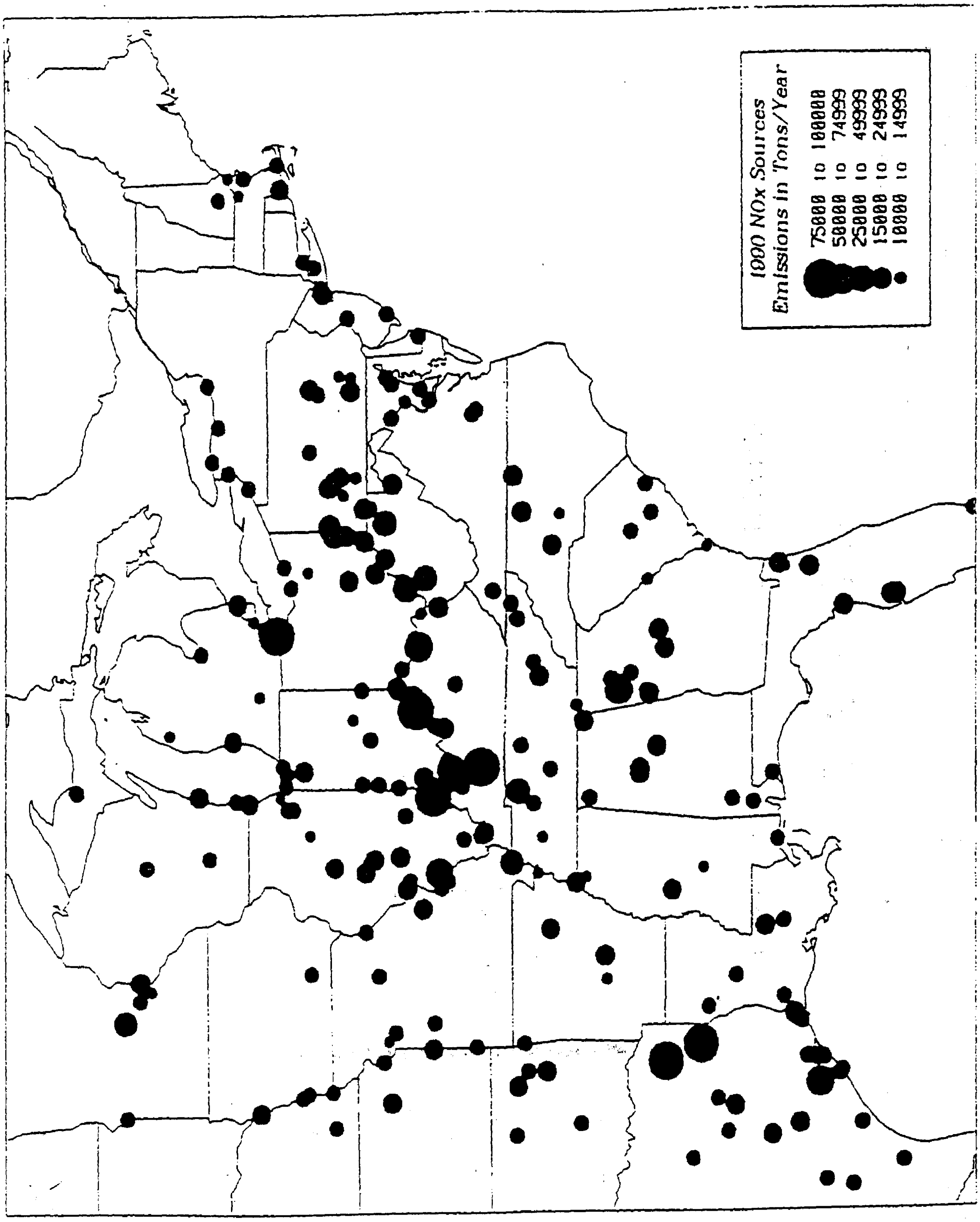
| | 1995 | | | | 1996 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | SEP | OCT | NOV | DEC | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
| **Policy Group** | | Decide Episode, Model, Resources<br>Review Summary of Phase I Control Measures. | | Review Phase II<br>Controls to Include in Strategies | | Decide Phase II<br>Control Strategies to evaluate | | | | | | | Hear Recommendations | | | Determine Recommendations to go to USEPA |
| **Model & Assessment** | | | | | | | | | | | | | | | | |
| Inventory | | Complete 1990 Base Inventory | | | | Complete Future Yr Inventory (Phase I) | | Complete Phase II Inventory | | | | | | | | |
| Modeling | Identify Episodes Model Resource Needs | | | | Complete development of model inputs (emissions & meteorolgy) | Complete Base Yr Modelling | Analysis & interpret of basecase modelling | Sensitivity analyses/ basecase modelling | Strategy modelling with Phase I control measures | Analysis and interpretation of strategy modelling w/ phase I control measures | | Strategy modeling with Phase II control measures | Analysis & interpretation of strategy modelling w/ Phase II control measures | | | |
| Air Quality Analysis | | | | | | Summarize aircraft measures | Traj - HY-SPLIT<br>New std. | | Rag datasets<br>Anal PAMS, SLAMS<br>Stat analysis<br>Apply obs models<br>Visualization<br>Eval Model Perf | | | Evaluate Model Performance | Compile and Interpret | | | |
| **Strategy & Controls** | | | | | | | | | | | | | | | | |
| Control Technology | ID Phase I Controls | | ID Potential Phase II Controls | | | | | | | | | | | | | |
| Implementation Strategies | | | | | Phase II Control Strategies (#, type) | | | | | | Complete Recommendation on Strategies including impediments | | | | | |
| Trading | | | | | | | | | | | | | Report on Regional Trading Option | | | |

10/02/95

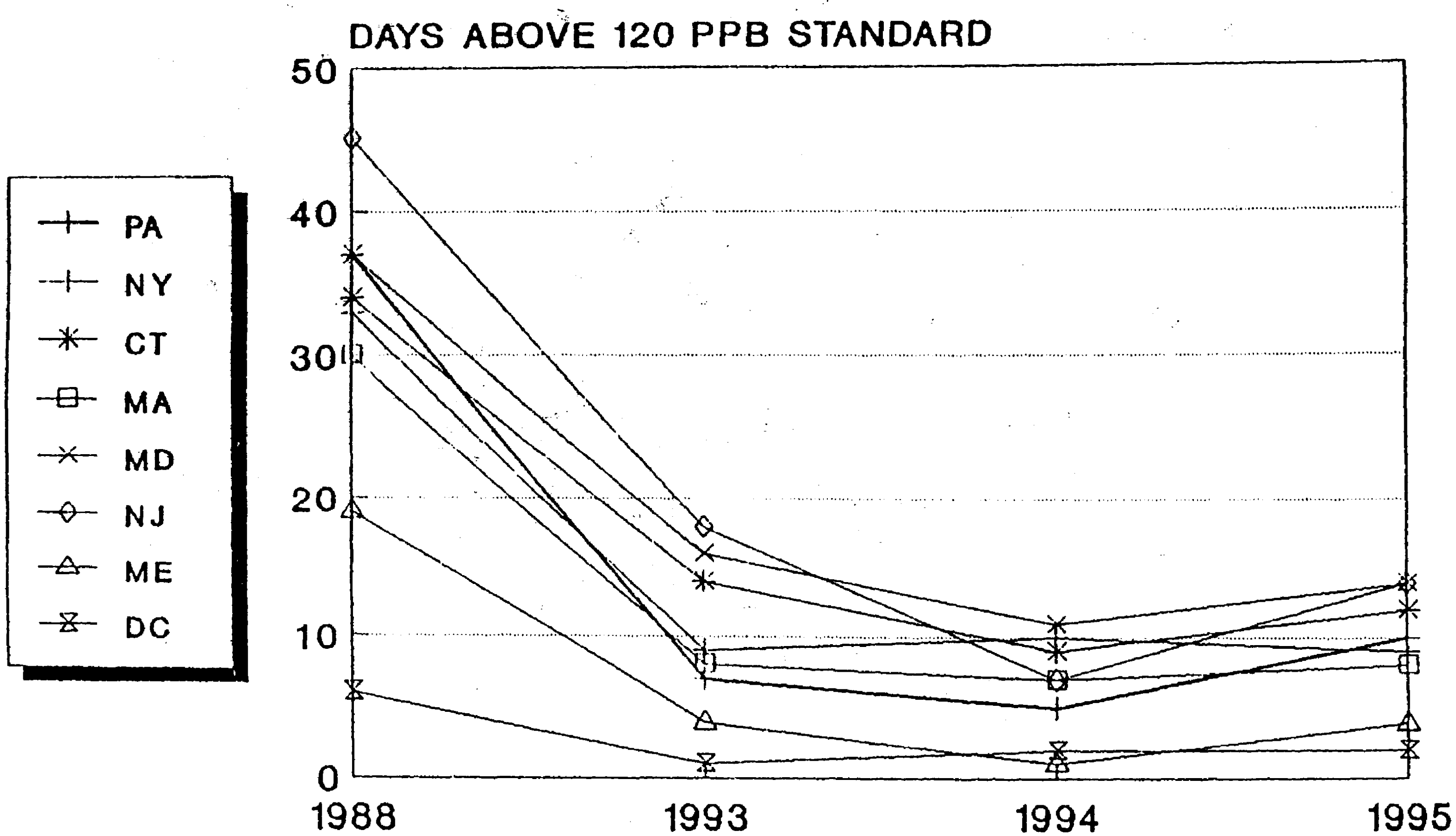
EUGENE M. TRISKO
ATTORNEY AT LAW*
P.O. BOX 596
BERKELEY SPRINGS, WV 25411

(304) 258-197
FAX (304) 258-3927
*ADMITTED IN DC ONLY

Coal and Energy Commission
Energy Preparedness Subcommittee
October 16, 1995

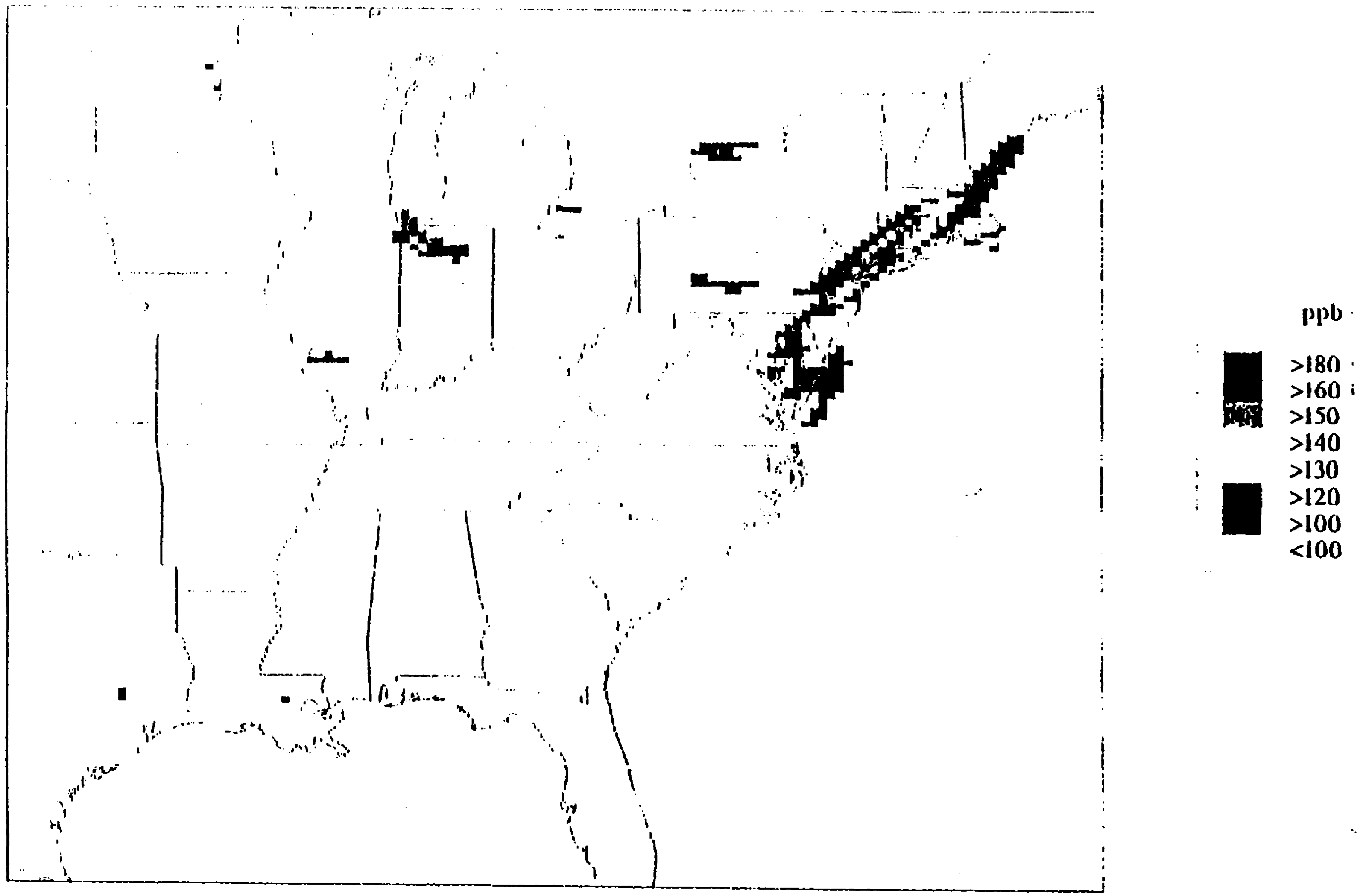

1990 NOx Sources
Emissions in Tons/Year
75000 to 100000
50000 to 74999
25000 to 49999
15000 to 24999
10000 to 14999

# DAYS ABOVE THE FEDERAL OZONE STANDARD STATES IN THE OZONE TRANSPORT REGION 1988 - 1995

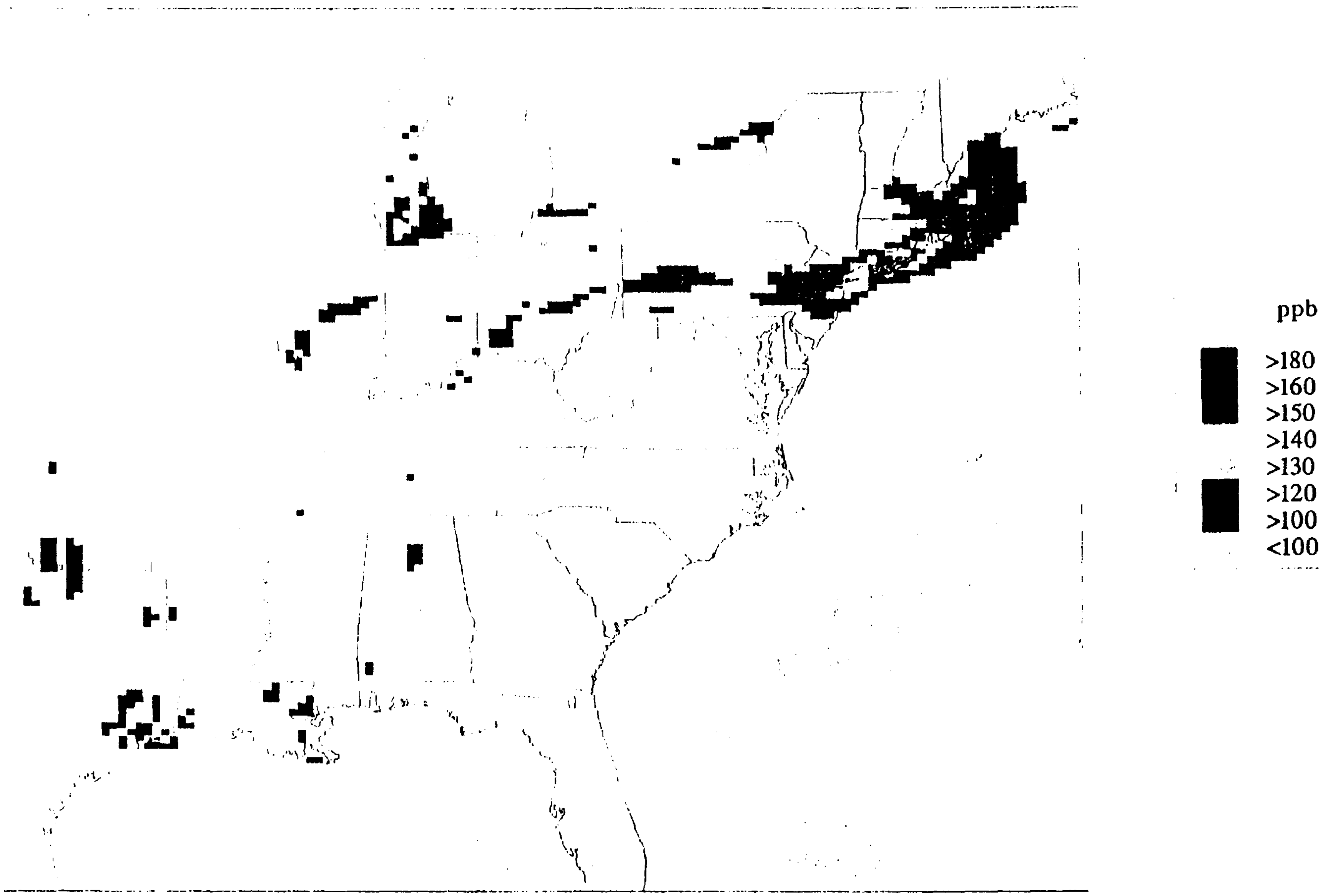



SOURCE: OTC

ROM 2005 Base Case
July 14 88 Daily Maximum Ozone



## ROM 2005 Base Case
## July 18 1991 Daily Maximum Ozone



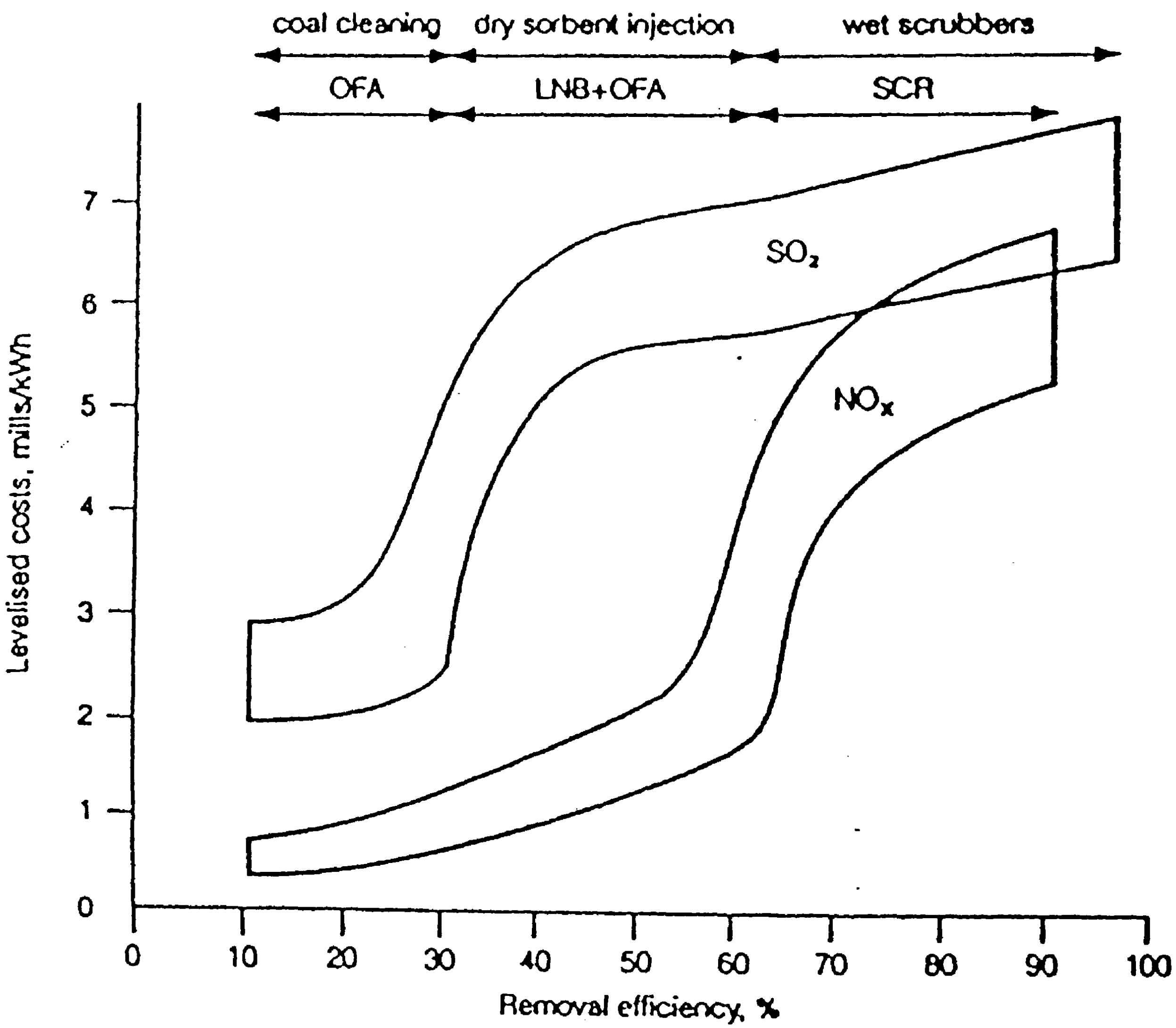
A_80

# Changes from ROM 2005 Base to Strategy E Relative to 0.12 ppm
## July 18 1991 Changes in Daily Maximum Ozone


| # | | |
|---|---|---|
| 42 | Ozone decreased; peak went from above to below .12 ppm | |
| → 4177 | Ozone decreased; peak was already below .12 ppm | |
| 78 | Ozone decreased; peak remained above .12 ppm | |
| → 11757 | No change; peak remained below .12 ppm | |

| | # |
|---|---|
| No change; remained above .12 ppm | 18 |
| Ozone increased; peak remained below .12 ppm | 53 |
| Ozone increased; peak was already above .12 ppm | 0 |
| Ozone increased; peak went from below to above .12 ppm | 1 |

a) Levelised costs in terms of mills/kWh



# BEYOND RACT: COSTS AND BENEFITS

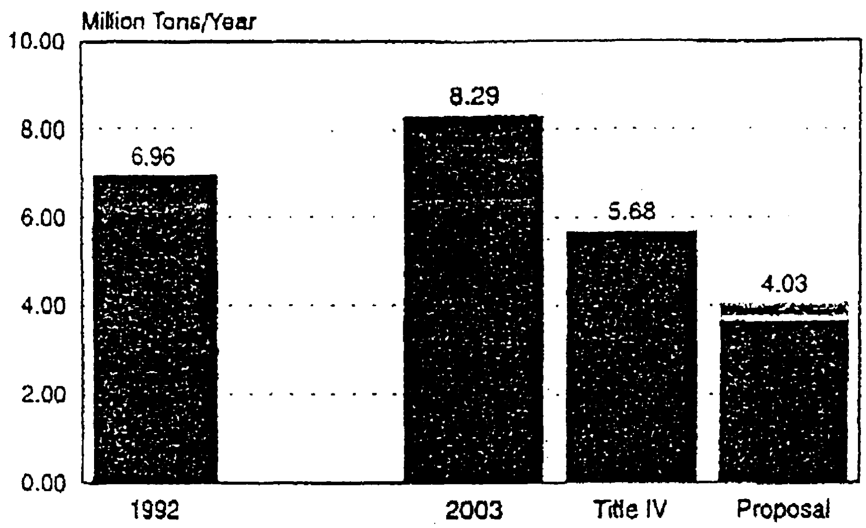
- **THE COST OF BEYOND RACT CONTROLS IN 32 STATES IS LIKELY TO EXCEED $5 BILLION ANNUALLY - COUNTING JUST DIRECT UTILITY COSTS**

- **EPA'S COMPUTER MODELS PREDICT THAT THESE $5 BILLION OF ANNUAL COSTS WOULD REDUCE OZONE IN THE NORTHEAST BY MERELY 6 TO 9 PARTS PER BILLION A FEW DAYS OF THE YEAR!**

- **SOME AREAS WOULD EXPERIENCE HIGHER SMOG LEVELS BECAUSE NITROGEN OXIDE EMISSIONS "SCAVENGE" OZONE**

# Utility NOx Emission Levels

## in 37 State Region



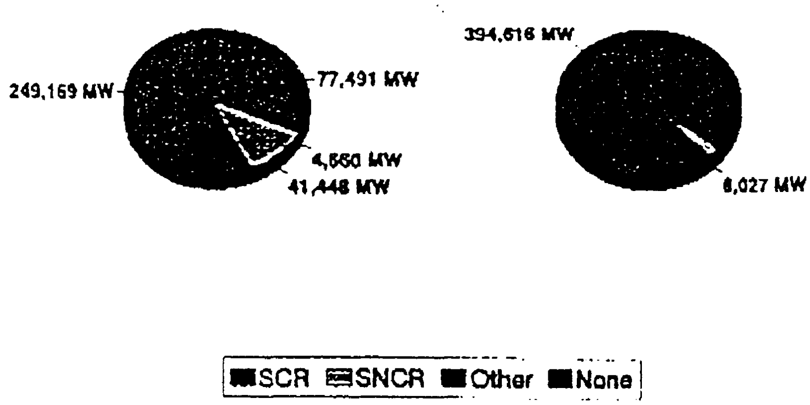

Excludes units <25 MW and new capacity

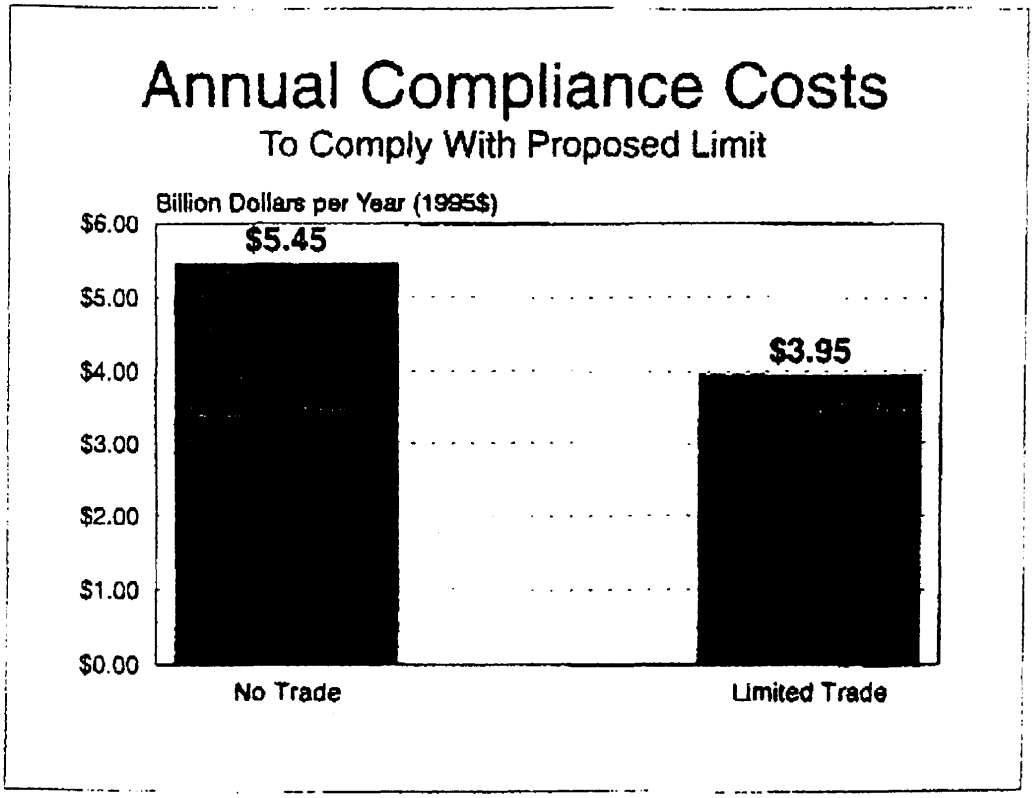
# Projected Compliance Strategies

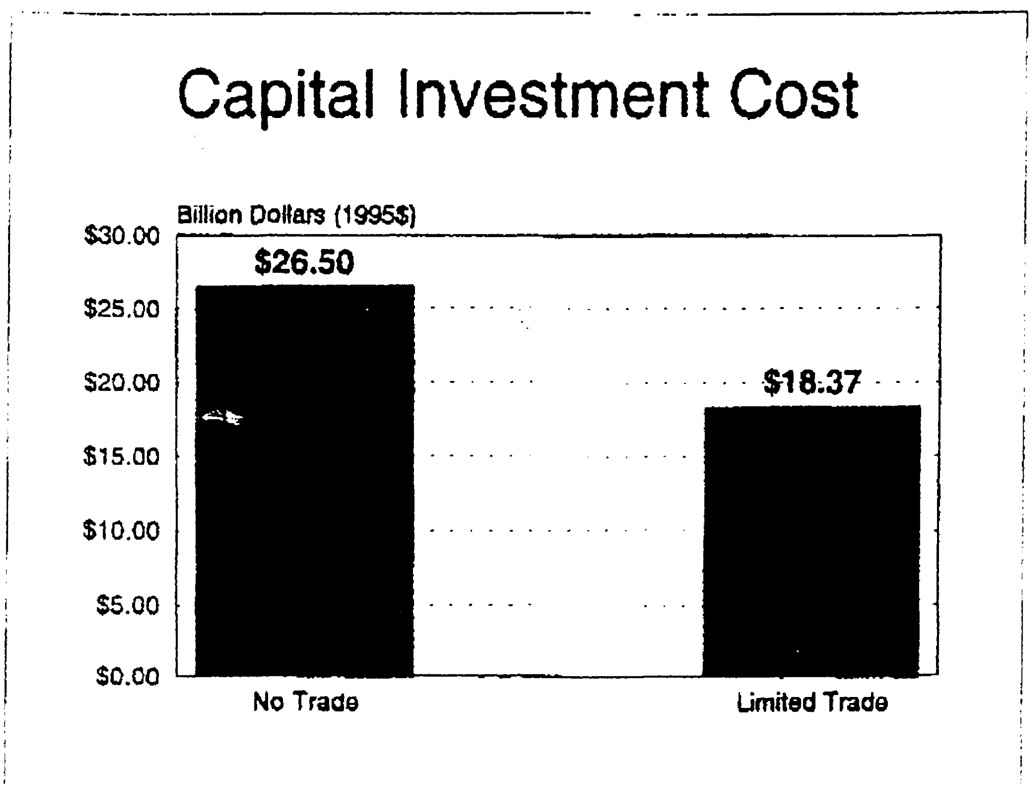
## for Expanded 37 State Region

Limited Intra-Utility Trading

No Trading




Annual Compliance Costs
To Comply With Proposed Limit
Billion Dollars per Year (1995$)
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
$5.45
$3.95
No Trade
Limited Trade


Capital Investment Cost
Billion Dollars (1995$)
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
$26.50
$18.37
No Trade
Limited Trade

## MODEL LEGISLATION:

- STATE LEGISLATION SHOULD ENSURE THOROUGH STUDY OF THE ECONOMIC IMPACTS OF INTERSTATE OZONE AGREEMENTS BEFORE STATE EPA'S ARE AUTHORIZED TO SIGN ON

    EMPLOYMENT IMPACTS
    ECONOMIC DEVELOPMENT
    HIGHER UTILITY RATES
    COMPETITIVENESS
    RISK OF "STRANDED UTILITY ASSETS"
    REGIONAL CONFLICTS - 32 VERSUS 18

**ENROLLED**

## VIRGINIA ACTS OF ASSEMBLY —CHAPTER

*An Act to require legislative approval of any proposed interstate agreement related to the transport of ozone and to require certain studies of the economic, employment, and competitive impacts of such a proposed agreement.*

[H 1512]

Approved

Whereas, the Clean Air Act Amendments of 1990 contain a comprehensive regulatory scheme for the control of emissions from mobile and stationary sources which will improve ambient air quality and health and welfare in all parts of the nation; and

Whereas, the number of areas failing to meet national ambient air quality standards for ozone has been declining steadily and will continue to decline with implementation of the Clean Air Act Amendments of 1990; and

Whereas, scientific research on the transport of ozone across state boundaries is proceeding under the auspices of the United States Environmental Protection Agency (EPA), state agencies and private entities, and this research will lead to improved scientific understanding of the causes and nature of ozone transport and emission control strategies potentially applicable thereto; and

Whereas, the Ozone Transport Commission established by the Clean Air Act Amendments of 1990 has proposed emission control requirements for stationary and mobile sources in certain northeastern states and the District of Columbia exceeding those mandated by federal law; and

Whereas, the Commonwealth of Virginia and other parties have challenged the constitutionality of The Ozone Transport Commission and its regulatory proposals under the Guarantee, Compact, and Joinder Clauses of the United States Constitution; and

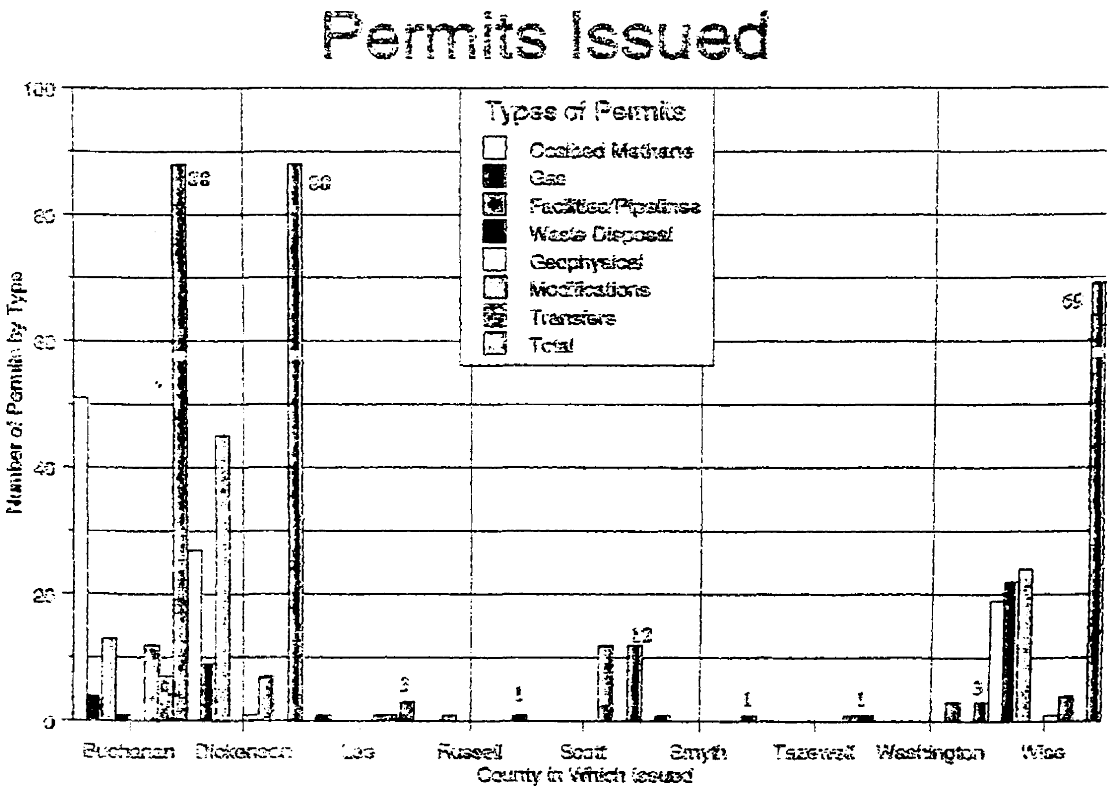
Whereas, the United States EPA, acting under color of federal law, is encouraging states east of and bordering the Mississippi River and Texas to develop and to enter into an interstate agreement on ozone transport requiring reductions in emissions of nitrogen oxides exceeding the requirements of the Clean Air Act Amendments of 1990; and

Whereas, before such an interstate agreement is entered into, the environmental benefits of such additional emission control requirements should be thoroughly weighed against any adverse effects such controls might have on state economic development, competitiveness, employment, or income; now, therefore,

**Be it enacted by the General Assembly of Virginia:**

**1.** *§ 1. Neither the Department of Environmental Quality nor any other agency of the Commonwealth shall, without the prior review and approval by resolution or other act of the General Assembly, enter into any interstate agreement related to the transport of ozone, if such agreement contains stationary source emission control requirements exceeding Reasonably Available Control Technology, as required by applicable law, or the nitrogen oxide emission limitations required by § 407 of Title IV of the Clean Air Act Amendments of 1990, 42 U.S.C. § 7651f.*

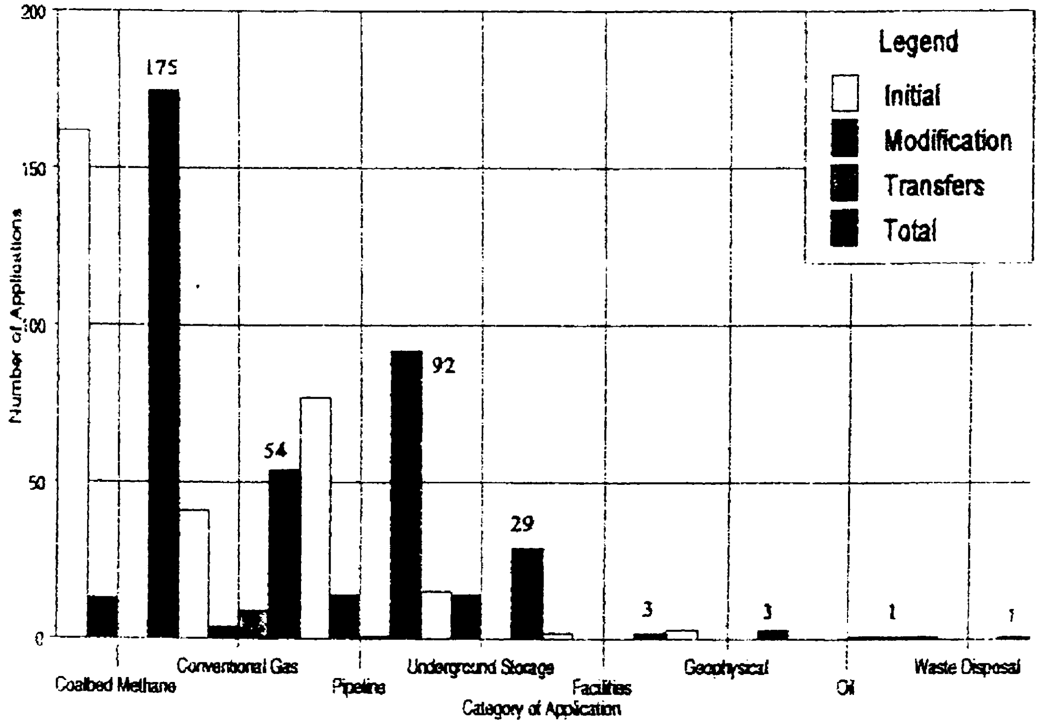
*§ 2. To assist the review and approval required by § 1, the Departments of Economic Development and Environmental Quality shall conduct a study of the impacts of any such proposed interstate ozone transport agreement on the Commonwealth's economy, including, but not limited to, impacts on economic development, employment, income, and industrial competitiveness and shall assess the alternative methods of achieving air quality standards. The State Corporation Commission and other agencies shall assist in the preparation of the study upon request. The study shall be submitted to the Chairmen of the House Committee on Conservation and Natural Resources and the Senate Committee on Agriculture, Conservation and Natural Resources not less than ten days prior to any scheduled hearing or other consideration of a proposed interstate agreement related to the transport of ozone.*




## Permits Issued by County and by Type

| | CBM | Gas | Facilities/ Pipelines | Waste Disposal | Modifi- cations | Transfers | Total |
|---|---|---|---|---|---|---|---|
| Buchanan | 51 | 4 | 13 | 1 | 12 | 7 | 88 |
| Dickenson | 27 | 9 | 45 | 0 | 7 | 0 | 88 |
| Lee | 0 | 1 | 0 | 0 | 1 | 1 | 3 |
| Russell | 0 | 0 | 1 | 0 | 0 | 0 | 1 |
| Scott | 0 | 0 | 0 | 0 | 12 | 0 | 12 |
| Smyth | 0 | 1 | 0 | 0 | 0 | 0 | 1 |
| Tazewell | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| Washington | 0 | 0 | 0 | 0 | 3 | 0 | 3 |
| Wise | 19 | 22 | 24 | 0 | 4 | 0 | 69 |
| Total | 97 | 37 | 83 | 1 | 39 | 9 | 266 |

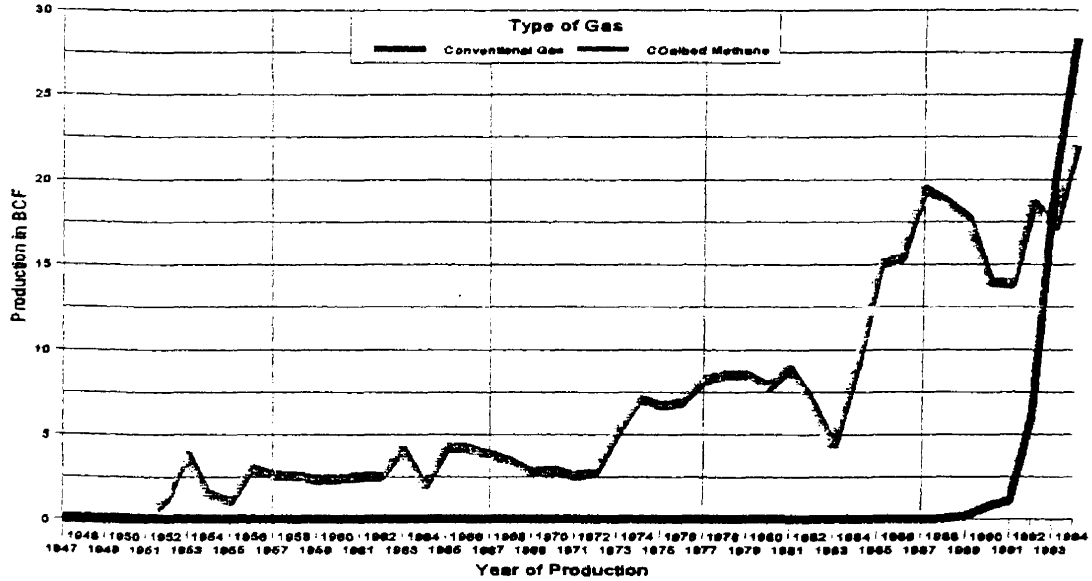
## Applications Received




### Applications Received by Type and Category

| | Initial | Modification | Transfers | Total |
|---|---|---|---|---|
| Coalbed Methane | 162 | 13 | 0 | 175 |
| Conventional Gas | 41 | 4 | 9 | 54 |
| Pipelines | 77 | 14 | 1 | 92 |
| UG Storage Wells | 15 | 14 | 0 | 29 |
| Facilities | 2 | 0 | 0 | 2 |
| Geophysical | 3 | 0 | 0 | 3 |
| Oil | 0 | 0 | 1 | 1 |
| Waste Disposal | 1 | 0 | 0 | 1 |
| Total | 301 | 45 | 11 | 357 |

## Virginia Gas Production 1947 - 1994

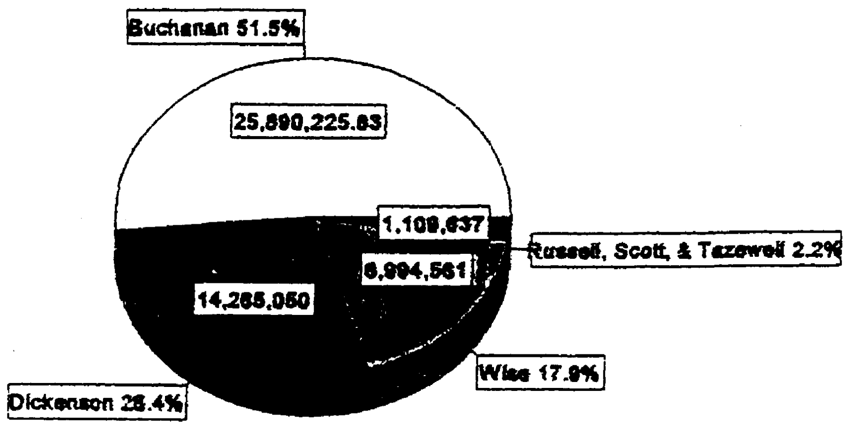



## Total Gas Produced

| Year | BCF | Year | BCF | Year | BCF | Year | BCF | CBM | Year | BCF | CBM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1947 | 0.06 | 1958 | 2.6 | 1969 | 2.8 | 1980 | 7.8 | | 1991 | 14.9 | 1.1 |
| 1948 | 0.07 | 1959 | 2.3 | 1970 | 2.9 | 1981 | 8.9 | | 1992 | 24.7 | 6 |
| 1949 | 0.07 | 1960 | 2.4 | 1971 | 2.6 | 1982 | 6.9 | | 1993 | 37 | 19.9 |
| 1950 | 0.07 | 1961 | 2.5 | 1972 | 2.8 | 1983 | 4.3 | | 1994 | 50.3 | 28.3 |
| 1951 | 0.07 | 1962 | 2.5 | 1973 | 5.1 | 1984 | 8.9 | | | | |
| 1952 | 1.2 | 1963 | 4.2 | 1974 | 7.1 | 1985 | 15 | | | | |
| 1953 | 3.9 | 1964 | 1.9 | 1975 | 6.7 | 1986 | 15.4 | | | | |
| 1954 | 1.5 | 1965 | 4.2 | 1976 | 6.9 | 1987 | 19.5 | | | | |
| 1955 | 1 | 1966 | 4.2 | 1977 | 8.2 | 1988 | 18.7 | | | | |
| 1956 | 3 | 1967 | 3.8 | 1978 | 8.5 | 1989 | 17.9 | 0.2 | | | |
| 1957 | 2.6 | 1968 | 3.4 | 1979 | 8.5 | 1990 | 14.8 | 0.8 | | | |

# Gas Production by County

(Percent Total Production)

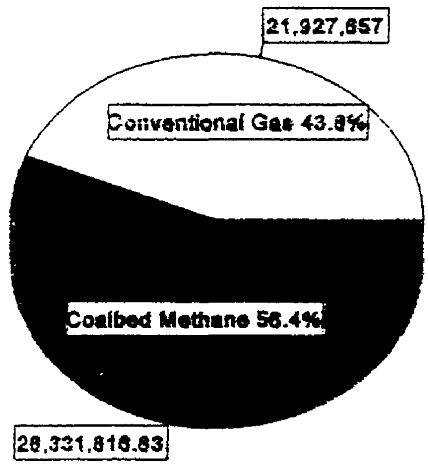



## Gas Production by County

| County | Number of Wells | Production (Mcf) | % of Total |
|---|---|---|---|
| Buchanan | 474 | 25,890,225.83 | 51.50 |
| Dickenson | 613 | 14,265,050 | 28.40 |
| Wise | 329 | 8,994,561 | 17.90 |
| Russell | 26 | 687,899 | 1.36 |
| Tazewell | 25 | 410,896 | .81 |
| Scott | 3 | 10,842 | .03 |
| **Total for State** | **1470** | **50,259,473.83** | **100.00** |

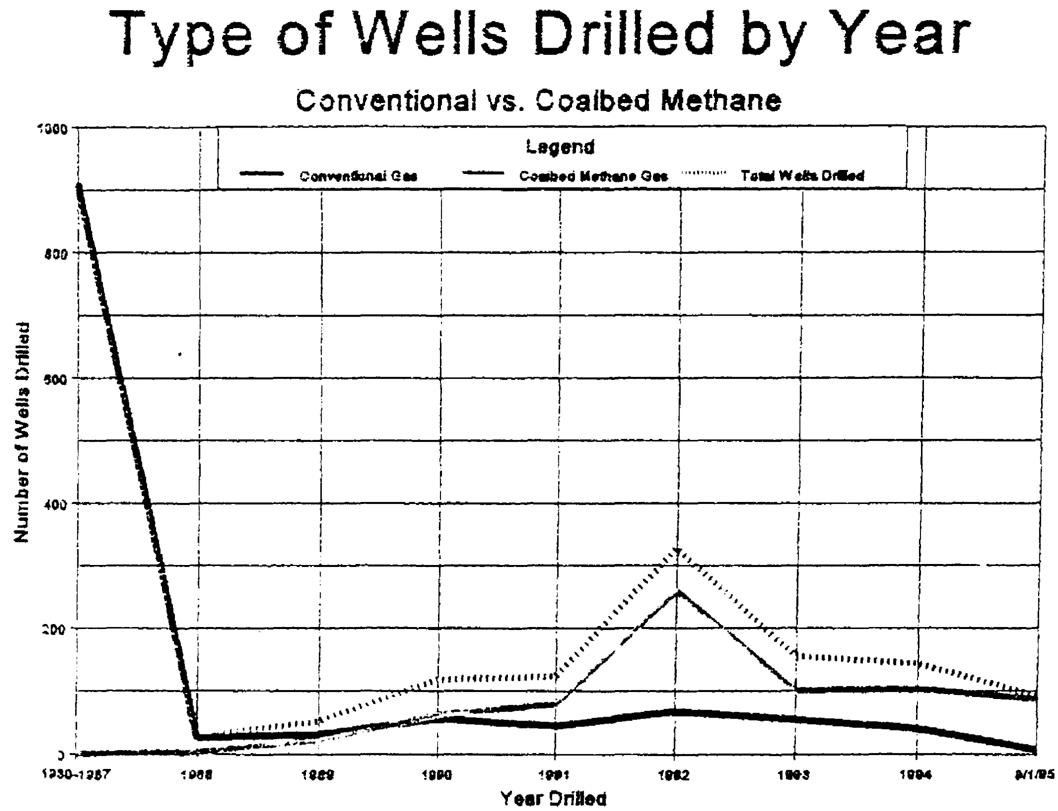
# Gas Production by Type

(Percent of Total)




## Gas Production by County by Type

| County | Conventional Gas (Mcf) | Coalbed Methane (Mcf) |
|---|---|---|
| **Buchanan** | 2,870,358 | 23,019,867.83 |
| **Dickenson** | 9,739,010 | 4,526,040 |
| **Russell** | 20,954 | 666,945 |
| **Scott** | 10,842 | 0 |
| **Tazewell** | 410,896 | 0 |
| **Wise** | 8,875,597 | 118,964 |
| **Total for State** | **21,927,657** | **28,331,816.83** |




## Wells Drilled by Type by Year

| Year Drilled | Gas | CBM | Total | % CBM |
|---|---|---|---|---|
| 1930 - 1987 | 911 | 0 | 911 | 0% |
| 1988 | 26 | 3 | 29 | 10% |
| 1989 | 31 | 21 | 52 | 40% |
| 1990 | 56 | 62 | 118 | 53% |
| 1991 | 44 | 79 | 123 | 64% |
| 1992 | 67 | 260 | 327 | 80% |
| 1993 | 55 | 101 | 156 | 65% |
| 1994 | 40 | 103 | 143 | 72% |
| 9-1-95 | 7 | 86 | 93 | 93% |

The following is a proposed list of requested changes to the Virginia Gas and Oil Act in order to reduce some restrictions and limitations on the operator's rights and ability to drill for gas and oil in the Commonwealth of Virginia.

1. STATUTORY CHANGE NO. 1

**Article 1, Section 45.1-361.12. Distance limitations of certain wells.--**

A. If the well operator and the objecting coal owners present or represented at the hearing to consider the objections to the proposed drilling unit or location are unable to agree upon a drilling unit or location for a new well within 2,500 linear feet of the location of an existing well or a well for which a permit application is on file, then ~~the permit~~ a suitable well location or drilling unit shall be ~~refused~~ determined by the Director.

* * * * * * * * * * *

COMMENTS: **Article 1, Section 45.1-361.12. Distance limitations of certain wells.--**

The way the statute is currently written it can adversely effect the correlative rights of the oil and gas mineral interest owner.

We are seeking a mediation process by which a fair and reasonable resolution to conflict between different mineral estate owners can be reached which will protect the interests of all mineral owners, but which will not preclude the oil and gas operators from efficiently and economically producing the Commonwealth's reserves.

This change in the Act would require the Director to identify and select an alternate location. Any decision rendered by the Director is appealable to the Oil and Gas Board.

By way of example, the situation can and has occurred in Virginia whereby an operator was precluded by the current statute from drilling a developmental well offsetting the same operator's best producing well.

Without this change the operator will essentially be "shut-out" from producing hundreds of thousands of dollars worth of reserves which impacts not only the operator, but the mineral interest owner as well as the Commonwealth.

2. **STATUTORY CHANGE NO. 2**

**Article 2, Section 45.1-361.15. Additional duties and responsibilities of the Board.--**

A. 5. Hear and decide appeals of Director's decisions and orders issued under Articles 1 and 3 of this chapter.

* * * * * * * * * * 

COMMENTS: **Article 2, Section 45.1-361.15. Additional duties and responsibilities of the Board.--**

The statutory change we are requesting in this section would simply allow the Board to hear and decide appeals of the Director's decisions under Article I of the statute in addition to Article III.

This statutory change is necessary to implement the change requested in 1. above.

3. **STATUTORY CHANGE NO. 3**

**Article 2, Section 45.1-361.17. Statewide spacing of wells.--**

A. Unless prior approval has been received from the board or a provision of the field or pool rules so allows:

1. Wells drilled in search of oil shall not be located closer than ~~1,320 feet~~ <u>1,250 feet</u> to any well completed in the same pool;

2. Wells drilled in search of gas shall not be located closer than ~~2,640 feet~~ <u>2,500 feet</u> to any other well completed in the same pool.

* * * * * * * * * *

<u>COMMENTS</u>: **Article 2, Section 45.1-361.17. Statewide spacing of wells.--**

Due to several factors, gas and oil operators in Virginia are forced to seek an inordinate number of variances or exceptions to statewide spacing.

In Southwest Virginia large tracts of land, whether surface or mineral tracts are owned by either the USFS or companies with potentially conflicting mineral interests. This ownership situation creates a scenario whereby an entity other than the oil and gas operator effectively selects the well location.

This factor, when coupled with the topographic problems an operator faces in Virginia, and with the fact that there were no minimum distance well spacing requirements before the enactment of the current statute has the effect of requiring an operator to seek variances on a regular basis.

In order to protect correlative rights, and to most efficiently produce the Commonwealth's reserves, operators attempt to locate wells for which they seek a variance as close to the statewide spacing as possible. The net effect of this is that operators often seek variances for exceptions to statewide spacing for distances of less than 140 feet.

For example, over the last five years, at least one-third (1/3) of one Virginia operator's requests for location exceptions would fit this scenario.

Furthermore, it costs an operator an average of $4000-$6000.00 to obtain a location exception. Thus, this statutory change would not only continue to protect correlative rights, but would also save the industry thousands of dollars over the long term.

This change to the statute would provide consistency with Article 1, Section 45.1-361.12.

4. **STATUTORY CHANGE NO. 4**

**Article 3, Section 45.1-361.29. Permit required; gas, oil or ~~geophysical operations~~; coalbed methane gas wells.--**

A. No person shall commence any ground disturbing activity for a well, gathering pipeline, ~~geophysical exploration~~ or associated activity, facilities or structures without first having obtained from the Director a permit to conduct such activity. Every permit application or permit modification application filed with the Director shall be verified by the permit applicant and shall contain all data maps, plats, plans and other information as required by regulation or the Director.

B. New permits issued by the Director shall be issued only for the following activities; ~~geophysical operations,~~ drilling, casing, equipping, stimulating, ~~and~~ producing, reworking, initially productive zones and plugging a well, or gathering pipeline construction and operation. ~~Applications of new permits to conduct geophysical operations shall be accompanied by an application fee of $100.~~ Applications for ~~all other~~ new permits shall be accompanied by an application fee of $200.

C. Prior to commencing any new zone completions or ~~reworking,~~ deepening ~~or plugging~~ of the well, or other activity not previously approved on the permitted site, a permittee shall first obtain a permit modification from the Director. All applications for permit modifications shall be accompanied by a permit modification fee of $100.

* * * * * * * * * *

COMMENTS: **Article 3, Section 45.1-361.29. Permits required; gas, oil, or geophysical operations; coalbed methane gas wells.--**

The current wording of subsection A, B & C to Section 45.1-361.29 requires new and potentially multiple permits at various stages in the continuous life of a gas/oil well. This is burdensome in the form of the time spent by the operator to put together permit packages and from an expense standpoint.

These new and additional permits are not required in neighboring states thereby hindering the competiveness of Virginia oil/gas industry.

Notification of coal owners during the process of plugging a well has been adequately addressed in the gas and oil regulations and is in large part a private, contractual arrangement outside the purview of the statute.

These changes would produce savings of time and money to both the well operator and the Commonwealth regulatory agency, in that it eliminates duplication and unnecessary administrative activity.

5.

## STATUTORY CHANGE NO. 5

**Article 3, Section 45.1-361.29. Permit required; gas, oil, or geophysical operations; coalbed methane gas wells.--**

F. A permit shall be required to drill any coalbed methane gas well or to convert any methane drainage borehole into a coalbed methane gas well. In addition to the other requirements of this section, every permit application for a coalbed methane gas well shall include:

. . . .

3. The coalbed methane gas well operator shall send a request for the consent to stimulate, by certified mail return receipt requested, to each coal operator as required by F.2a (above). Failure to respond within 30 days of receipt by the coal operator shall have the same force and effect as if the consent to stimulate had been granted.

~~3.~~ 4. . . . .

G. In the absence of the applicant submitting the consent described in subsection F.2a. above, the applicant may submit a request for a hearing before the board accompanied by an affidavit which shall include the following:

(1) A statement that a coal owner or operator as described in subsection F.2a. of this section has refused to provide written authorization to stimulate the well;

(2) A statement detailing the efforts undertaken to obtain such authorization;

(3) A statement setting out any known reasons for the authorization not being provided; and

(4) A statement or other information necessary to provide prima facie evidence that the proposed method of stimulation will not render the coal seam unworkable, or considering all factors, impair mine safety.

Upon receipt of a request and affidavit the Director shall forward the application to the board to consider the proposed stimulation, or if other objections or notices are filed requiring a hearing before the board, the request hereunder may be included for consideration by the board along with other matters related to the application.

If the Director finds that authorization of a coal owner or operator has been withheld based upon reasons related to safety the Director shall,

?

concurrent with submission of the request and affidavit to the board, submit a copy of the application to the director of the Department of Mine Safety who shall review the application as to issues of mine safety and within thirty days submit recommendations to the board.

~~G.~~H. . . .

* * * * * * * * * * *

**COMMENTS**: Article 3, Section 45.1-361.29. Permit required; gas, oil, or ~~geophysical operations~~; coalbed methane gas wells.--

Here, we are requesting that additional language be added to sub-section F and a new sub-section be added to establish an appeals process. These requested changes are interrelated and as such should be analyzed and interpreted together. As the statute is currently written the coal owner/operator may simply refuse to respond to the applicant's request for consent to stimulate. This simply prohibits the permit from being issued resulting in a loss of time, monies and mineral reserves. It is important to note the preparation and cost of an average permit application is approximately $ 5000 . The failure to respond to the applicant's request for consent to stimulate unfairly and adversely effects the correlative rights of the mineral owner.

Virginia is the leading producer of coalbed methane in the Appalachian Basin, yet the lack of either a mediation or an appeal process pertaining to a coal operator's failure to grant a consent to stimulate puts Virginia at a competitive disadvantage. Both the federal government and the neighboring state of West Virginia have enacted legislation which includes such an appeal process, and Kentucky has proposed laws which include the same.

By requesting these changes the gas and oil industry is seeking a level playing field on which competing mineral interests work together for the most efficient and effective production of all the Commonwealth's minerals.

6. <u>STATUTORY CHANGE NO. 6</u>

**Article 3 Section 45.1-361.30. Notice of permit applications and permit modification applications required; content.--**

D. All notices required to be given pursuant to subsections A, B and C of this section shall contain a statement of the time within which objections may be made and the name and address of the person to whom objections shall be forwarded. Only those persons entitled to notice under subsections A, B, and C of this section shall have standing to object to the issuance of the proposed permit or permit modification for a gas, <u>or</u> oil ~~or geophysical~~ operation as the use may be. <u>Upon receipt of notice any person may waive the time and right to object.</u>

E. Within one day of the day on which the application for a permit is filed, the applicant shall provide notice to (i) the local governing body or chief executive officer of the county, city, or town in which the well is proposed to be located and (ii) the general public, <u>only in those cases where the property owners requiring notice cannot be located or identified,</u> through publication of a notice in at least one newspaper of general circulation in the county, city or town where the well is proposed to be located.

* * * * * * * * * *

<u>COMMENTS</u>: **Article 3, Section 45.1-361.30. Notice of permit applications and permit modification application required; content.--**

In subsection D we are requesting a mechanism by which those persons entitled to notice may sign a statement of no objection to the issuance of the permit prior to the expiration of the current 15 day period.

This revision would have the effect of increasing the operator's efficiency and flexibility in the implementation of its drilling program.

The persons entitled to notice are delineated in subdivisions 1, 2, & 3 of subsection A of Section 361.30. Nowhere within this delineation does one find "the general public."

The requirement in subsection E of the current statute requiring notice to the general public is there for the sole purpose of publication notice to interest owners who cannot be located or identified.

?

<u>concurrent with submission of the request and affi~~davit to the~~ board, submit a copy of the application to the director of the Department of Mine Safety who shall review the application as to issues of mine safety and within thirty days submit recommendations to the board.</u>

~~G.~~<u>H</u>. . . .

* * * * * * * * * * *

<u>COMMENTS</u>: Article 3, Section 45.1-361.29. Permit required; gas, oil, or ~~geophysical operations~~; coalbed methane gas wells.--

Here, we are requesting that additional language be added to sub-section F and a new sub-section be added to establish an appeals process. These requested changes are interrelated and as such should be analyzed and interpreted together. As the statute is currently written the coal owner/operator may simply refuse to respond to the applicant's request for consent to stimulate. This simply prohibits the permit from being issued resulting in a loss of time, monies and mineral reserves. It is important to note the preparation and cost of an average permit application is approximately $ 5000 . The failure to respond to the applicant's request for consent to stimulate unfairly and adversely effects the correlative rights of the mineral owner.

Virginia is the leading producer of coalbed methane in the Appalachian Basin, yet the lack of either a mediation or an appeal process pertaining to a coal operator's failure to grant a consent to stimulate puts Virginia at a competitive disadvantage. Both the federal government and the neighboring state of West Virginia have enacted legislation which includes such an appeal process, and Kentucky has proposed laws which include the same.

By requesting these changes the gas and oil industry is seeking a level playing field on which competing mineral interests work together for the most efficient and effective production of all the Commonwealth's minerals.

6. STATUTORY CHANGE NO. 6

**Article 3 Section 45.1-361.30. Notice of permit applications and permit modification applications required; content.--**

D. All notices required to be given pursuant to subsections A, B and C of this section shall contain a statement of the time within which objections may be made and the name and address of the person to whom objections shall be forwarded. Only those persons entitled to notice under subsections A, B, and C of this section shall have standing to object to the issuance of the proposed permit or permit modification for a gas, or oil ~~or geophysical~~ operation as the use may be. Upon receipt of notice any person may waive the time and right to object.

E. Within one day of the day on which the application for a permit is filed, the applicant shall provide notice to (i) the local governing body or chief executive officer of the county, city, or town in which the well is proposed to be located and (ii) the general public, only in those cases where the property owners requiring notice cannot be located or identified, through publication of a notice in at least one newspaper of general circulation in the county, city or town where the well is proposed to be located.

* * * * * * * * * *

COMMENTS: **Article 3, Section 45.1-361.30. Notice of permit applications and permit modification application required; content.--**

In subsection D we are requesting a mechanism by which those persons entitled to notice may sign a statement of no objection to the issuance of the permit prior to the expiration of the current 15 day period.

This revision would have the effect of increasing the operator's efficiency and flexibility in the implementation of its drilling program.

The persons entitled to notice are delineated in subdivisions 1, 2, & 3 of subsection A of Section 361.30. Nowhere within this delineation does one find "the general public."

The requirement in subsection E of the current statute requiring notice to the general public is there for the sole purpose of publication notice to interest owners who cannot be located or identified.

?

concurrent with submission of the request and affidavit to the board, submit a copy of the application to the director of the Department of Mine Safety who shall review the application as to issues of mine safety and within thirty days submit recommendations to the board.

~~G.~~H. . . .

* * * * * * * * * * *

COMMENTS: Article 3, Section 45.1-361.29. Permit required; gas, oil, or ~~geophysical operations~~; coalbed methane gas wells.--

Here, we are requesting that additional language be added to sub-section F and a new sub-section be added to establish an appeals process. These requested changes are interrelated and as such should be analyzed and interpreted together. As the statute is currently written the coal owner/operator may simply refuse to respond to the applicant's request for consent to stimulate. This simply prohibits the permit from being issued resulting in a loss of time, monies and mineral reserves. It is important to note the preparation and cost of an average permit application is approximately $ 5000 . The failure to respond to the applicant's request for consent to stimulate unfairly and adversely effects the correlative rights of the mineral owner.

Virginia is the leading producer of coalbed methane in the Appalachian Basin, yet the lack of either a mediation or an appeal process pertaining to a coal operator's failure to grant a consent to stimulate puts Virginia at a competitive disadvantage. Both the federal government and the neighboring state of West Virginia have enacted legislation which includes such an appeal process, and Kentucky has proposed laws which include the same.

By requesting these changes the gas and oil industry is seeking a level playing field on which competing mineral interests work together for the most efficient and effective production of all the Commonwealth's minerals.

6. <u>STATUTORY CHANGE NO. 6</u>

**Article 3 Section 45.1-361.30. Notice of permit applications and permit modification applications required; content.--**

D. All notices required to be given pursuant to subsections A, B and C of this section shall contain a statement of the time within which objections may be made and the name and address of the person to whom objections shall be forwarded. Only those persons entitled to notice under subsections A, B, and C of this section shall have standing to object to the issuance of the proposed permit or permit modification for a gas, <u>or</u> oil ~~or geophysical~~ operation as the use may be. <u>Upon receipt of notice any person may waive the time and right to object</u>.

E. Within one day of the day on which the application for a permit is filed, the applicant shall provide notice to (i) the local governing body or chief executive officer of the county, city, or town in which the well is proposed to be located and (ii) the general public, <u>only in those cases where the property owners requiring notice cannot be located or identified,</u> through publication of a notice in at least one newspaper of general circulation in the county, city or town where the well is proposed to be located.

* * * * * * * * * * *

<u>COMMENTS</u>: **Article 3, Section 45.1-361.30. Notice of permit applications and permit modification application required; content.--**

In subsection D we are requesting a mechanism by which those persons entitled to notice may sign a statement of no objection to the issuance of the permit prior to the expiration of the current 15 day period.

This revision would have the effect of increasing the operator's efficiency and flexibility in the implementation of its drilling program.

The persons entitled to notice are delineated in subdivisions 1, 2, & 3 of subsection A of Section 361.30. Nowhere within this delineation does one find "the general public."

The requirement in subsection E of the current statute requiring notice to the general public is there for the sole purpose of publication notice to interest owners who cannot be located or identified.

The changes requested herein are simply clarification of statutory intent. Publication notice costs the operator between $80.00 to $100.00 per well, and in the majority of cases all interest owners have been identified and located. Again, this is a change that complies with statutory intent and would save the operator money.

7. **STATUTORY CHANGE NO. 7**

**Article 3 Section 45.1-361.33. Expiration of permits.--**

All permits issued pursuant to this chapter shall expire ~~twenty-four~~ forty-eight months from their date of issuance unless the permitted activity has commenced within that time period. An operator may renew the existing permit for an additional forty-eight months by submitting written request and remitting a $250.00 renewal fee within 90 days after the expiration date.

* * * * * * * * * *

COMMENTS: **Article 3 Section 45.1-361.33. Expiration of permits.--**

The revisions in this section would allow the gas and oil operator who has spent between $10,000 and $20,000 in time and money obtaining a permit to have the ability to renew the permit without going through the entire permit application process again. Currently the law limits the life of a permit to 2 years. This is simply not long enough considering the investment which was made to originally acquire the permit.

It is not unusual within the industry for the drilling of a well to be delayed for a lengthy period of time line due to several factors; including geological reasons, economics, pipeline access and market conditions.

8. **STATUTORY CHANGE NO. 8**

**Article 2, Section 45.1-361.21. Pooling of interests in drilling units.--**

E. Any person who does not make an election under the pooling order shall be deemed, subject to a final legal determination of ownership, to have leased his gas or oil interest to the gas or oil well operator as the pooling order may provide.

~~E.~~ F. . . .

~~F.~~ G. . . .

~~G.~~ H. . . .

* * * * * * * * * * *

**COMMENTS: Article 2, Section 45.1-361.21. Pooling of interests in drilling units.--**

The Virginia Gas and Oil Act allows for the compulsory pooling of interests pursuant to Section 45.1-361.21 and 45.1-361.22. Section 45.1-261.22 (the statutory section by which interests are pooled for coalbed methane wells) provides that a person failing to make any election under the pooling order shall be deemed to have leased his interest to the operator named in the pooling order.

The Order issued by the VGOB subsequent to the force pooling hearing also contains the "deemed to have leased" provision. Section 45.1-361.21 (the section under which units for conventional gas wells are established) does nct provide this provision.

The statutory revision we are requesting would make the pooling statutes and Board Order consistent with one another.

The language would clarify the intent of the statute and prevent potential litigation over this issue.

9. **STATUTORY CHANGE NO. 9**

The term "geophysical" at each and every place it occurs in the statute.

Comments: **The term "geophysical" at each and every place it occurs in the statute.**

Finally, we hereby propose a general, statute wide change in that we would request the elimination of the term "geophysical" at each and every place it occurs in the statute.

This change would enable operators to obtain a permit to drill a core hole in a day by filing a one or two page form, whereas under the current law, the process is basically the same as obtaining a permit for a gas well.

[e:\voga\vabill.2]

965528757



# SENATE BILL NO. 286

Offered January 19, 1996

*A BILL to amend and reenact § 15.1-1638 of the Code of Virginia, relating to the Virginia Coalfield Economic Development Authority.*

---

Patrons—Wampler and Colgan; Delegates: Councill, Grayson, Parrish, Thomas and Watkins

---

Referred to the Committee on Local Government

---

**Be it enacted by the General Assembly of Virginia:**

**1. That § 15.1-1638 of the Code of Virginia is amended and reenacted as follows:**

§ 15.1-1638. Board of Authority; members and officers; staff; annual report.

All powers, rights and duties conferred by this chapter, or other provisions of law, upon the Authority shall be exercised by the Board of the Virginia Coalfield Economic Development Authority, hereinafter referred to as the Board or the Board of the Authority. Board members shall serve for terms of four years except that all vacancies shall be filled for the unexpired term. All terms shall commence July 1 of the year of appointment. Initial appointments shall begin July 1, 1988. The Board shall consist of ~~fifteen~~ *sixteen* members, residents of the Commonwealth, as follows:

Three initial members shall be the sitting chairmen of the county boards of supervisors of the three counties which are the three largest contributors to the coal and gas road improvement fund for the fiscal year immediately preceding July 1, 1988, as reported by the treasurers of the affected counties and city. Every four years thereafter, the three members shall be supervisors from the county boards of supervisors of the three counties which are the three largest contributors to the Virginia Coalfield Economic Development Fund for the fiscal year immediately preceding July 1 of the year in which new terms of members are to begin. Such supervisors shall be selected by their respective county boards of supervisors.

Five members shall be appointed by the Governor at large, provided that if there be any participating county or city in which there resides no member of the Board appointed by the other methods herein specified, the Governor shall include at least one member who is a resident of each such county or city among his appointees. For the first four-year terms these five members shall be selected to the extent possible from former members of the Southwest Virginia Economic Development Commission who reside in Planning District 1 or 2.

One member shall be a representative of the Virginia Department of Economic Development, as designated by the Director of the Department.

One member shall be a representative named by the Virginia Coal Association.

Two members shall be the Executive Directors of the LENOWISCO and Cumberland Plateau Planning District Commissions.

Three initial members shall be representatives named by the three largest coal producers determined by the dollar value of their contribution to the respective county coal and gas road improvement funds for the fiscal year immediately preceding July 1, 1988, as reported by the treasurers of the affected counties and city. Every four years thereafter, the three members shall be representatives named by the three largest coal producers determined by the dollar value of their contributions to the Virginia Coalfield Economic Development Fund for the fiscal year immediately preceding July 1 of the year in which new terms of members are to begin.

*One member shall be a representative named by the largest oil and gas producer determined by the dollar value of its contributions to the Virginia Coalfield Economic Development Fund for the fiscal year immediately preceding July 1 of the year in which new terms of members are to begin.*

Should a member who is a member solely by virtue of his office as member of a board of supervisors or executive director of a planning district commission cease to hold such office, then an immediate vacancy shall occur, and the vacancy shall be filled for the remainder of the term by his successor selected by the board of supervisors of his county or as executive director.

Each member of the Board shall, before entering upon the discharge of the duties of this office, take and subscribe the oath prescribed in § 49-1. They shall receive their expenses spent on business of the Authority.

Ten members of the Authority shall constitute a quorum and the affirmative vote of a majority of the quorum present shall be necessary for any action taken by the Authority. No vacancy in the membership of the Authority shall impair the right of a quorum to exercise all the rights and perform all the duties of the Authority.

The Board shall elect from its membership a chairman, a vice-chairman, a treasurer and a secretary for each calendar year. The secretary shall keep the minutes of the Board and affix the seal of the Authority.

The Board may also appoint an executive director, an assistant treasurer and an assistant secretary, and staff to assist same, who shall discharge such functions as may be directed by the Board.

Staff functions of the Authority may be undertaken by the LENOWISCO and Cumberland Plateau Planning District Commissions, as agreed by the Board and participating Commissions.

The Board, promptly following the close of the calendar year, shall submit an annual report of the Authority's activities for the preceding year to the Governor, the General Assembly, the boards of supervisors of the seven coalfield counties and the Norton City Council. Each such report shall set forth a complete operating and financial statement covering the operation of the Authority during such year. The Authority shall cause an audit of its books and accounts to be made at least once each year by a certified public accountant and the cost thereof may be treated as part of the expense of operation.

Official Use By Clerks

| **Passed By The Senate** | | **Passed By The House of Delegates** | |
|---|---|---|---|
| without amendment | ☐ | without amendment | ☐ |
| with amendment | ☐ | with amendment | ☐ |
| substitute | ☐ | substitute | ☐ |
| substitute w/amdt | ☐ | substitute w/amdt | ☐ |
| Date: ____________ | | Date: ____________ | |
| Clerk of the Senate | | Clerk of the House of Delegates | |

965527757

**SENATE BILL NO. 285**

Offered January 19, 1996

*A BILL to amend and reenact § 9-145.2 of the Code of Virginia, relating to the Virginia Coal and Energy Commission.*

---

Patrons—Wampler, Colgan and Reasor; Delegates: Abbitt, Almand, Councill, Grayson, Parrish, Stump, Thomas and Watkins

---

Referred to the Committee on Rules

---

**Be it enacted by the General Assembly of Virginia:**

**1. That § 9-145.2 of the Code of Virginia is amended and reenacted as follows:**

§ 9-145.2. Membership; terms; vacancies; chairman; compensation.

A. The Commission shall consist of twenty members, of whom five shall be appointed by the Committee on Privileges and Elections of the Senate from the membership of the Senate, eight shall be appointed by the Speaker of the House of Delegates from the membership thereof and seven shall be appointed from the Commonwealth at large by the Governor. The at-large appointees shall include representatives of industry, government and groups or organizations identified with ~~coal and energy~~ production and conservation *of coal, natural gas, and energy*.

B. The terms of office of the legislative members shall be coincident with their service in the house from which appointed; the appointees of the Governor shall serve for terms of four years and their successors shall be appointed for like terms, but vacancies occurring other than by expiration of term shall be filled for the unexpired term. Any member may be reappointed for successive terms.

C. The members of the Commission shall elect its own chairman annually.

D. Legislative members of the Commission shall receive such compensation as is set forth in § 14.1-18 and all members shall be reimbursed for their actual expenses incurred by them in the performance of their duties in the work of the Commission.

Official Use By Clerks

| Passed By The Senate | | Passed By The House of Delegates | |
|---|---|---|---|
| without amendment | ☐ | without amendment | ☐ |
| with amendment | ☐ | with amendment | ☐ |
| substitute | ☐ | substitute | ☐ |
| substitute w/amdt | ☐ | substitute w/amdt | ☐ |
| Date: ______ | | Date: ______ | |
| Clerk of the Senate | | Clerk of the House of Delegates | |

965586757

**SENATE BILL NO. 476**

AMENDMENT IN THE NATURE OF A SUBSTITUTE

(Proposed by the House Committee on Mining and Mineral Resources on February 28, 1996)

(Patron Prior to Substitute—Senator Wampler)

*A BILL to amend and reenact §§ 45.1-361.17, 45.1-361.21, 45.1-361.29, 45.1-361.30, 45.1-361.33 and 45.1-361.35 of the Code of Virginia, relating to the Gas and Oil Act.*

**Be it enacted by the General Assembly of Virginia:**

**1. That §§ 45.1-361.17, 45.1-361.21, 45.1-361.29, 45.1-361.30, 45.1-361.33 and 45.1-361.35 of the Code of Virginia are amended and reenacted as follows:**

§ 45.1-361.17. Statewide spacing of wells.

A. Unless prior approval has been received from the Board or a provision of the field or pool rules so allows:

1. Wells drilled in search of oil shall not be located closer than 1,320 feet to any well completed in the same pool;

2. Wells drilled in search of gas shall not be located closer than ~~2,640~~ *2,500* feet to any other well completed in the same pool; and

3. A well shall not be drilled closer to the boundary of the acreage supporting the well, whether such acreage is a single leasehold or other tract or a contractual or statutory drilling unit, than one-half of the minimum well spacing distances prescribed in this section.

B. Unless prior approval has been received from the Board or a provision of the field or pool rules so allows:

1. Wells drilled in search of coalbed methane gas shall not be located closer than 1,000 feet to any other coalbed methane gas well, or in the case of coalbed methane gas wells located in the gob, such wells shall not be located closer than 500 feet to any other coalbed methane gas wells located in the gob.

2. A coalbed methane gas well shall not be drilled closer than 500 feet, or in the case of such well located in the gob, not closer than 250 feet, from the boundary of the acreage supporting the well, whether such acreage is a single leasehold or other tract or a ~~contractural~~ *contractual* or statutory drilling unit.

3. The spacing limitations set forth in this subsection are subject to the provisions of §§ 45.1-361.11 and 45.1-361.12.

§ 45.1-361.21. Pooling of interests in drilling units.

A. The Board, upon application from any gas or oil owner, shall enter an order pooling all interests in the drilling unit for the development and operation thereof when:

1. Two or more separately owned tracts are embraced in a drilling unit;

2. There are separately owned interests in all or part of any such drilling unit and those having interests have not agreed to pool their interests; or

3. There are separately owned tracts embraced within the minimum statewide spacing requirements prescribed in § 45.1-361.17.

However, no pooling order shall be entered until the notice and hearing requirements of this article have been satisfied.

B. Subject to any contrary provision contained in a gas or oil lease respecting the property, gas or oil operations incident to the drilling of a well on any portion of a unit covered by a pooling order shall be deemed to be the conduct of such operations on each tract in the unit. The portion of production allocated to any tract covered by a pooling order shall be in the same proportion as the acreage of that tract bears to the total acreage of the unit.

C. All pooling orders entered by the Board pursuant to the provisions of this section shall:

1. Authorize the drilling and operation of a well, including the stimulation of all coal seams in the case of a coalbed methane well when authorized pursuant to clause (iii) of subdivision 2b of subsection F of § 45.1-361.29, subject to the permit provisions contained in Article 3 (§ 45.1-361.27 et seq.) of this chapter;

2. Include the time and date when such order expires;

3. Designate the gas or oil owner who is authorized to drill and operate the well; provided,

however, that except in the case of coalbed methane gas wells, the designated operators must have the right to conduct operations or have the written consent of owners with the right to conduct operations on at least twenty-five percent of the acreage included in the unit;

4. Prescribe the conditions under which gas or oil owners may become participating operators or exercise their rights of election under subdivision 7 of this subsection;

5. Establish the sharing of all reasonable costs, including a reasonable supervision fee, between participating operators so that each participating operator pays the same percentage of such costs as his acreage bears to the total unit acreage;

6. Require that nonleasing gas or oil owners be provided with reasonable access to unit records submitted to the Director or Inspector;

7. Establish a procedure for a gas or oil owner who received notice of the hearing and who does not decide to become a participating operator may elect either to (i) sell or lease his gas or oil ownership to a participating operator, (ii) enter into a voluntary agreement to share in the operation of the well at a rate of payment mutually agreed to by the gas or oil owner and the gas or oil operator authorized to drill the well, or (iii) share in the operation of the well as a nonparticipating operator on a carried basis after the proceeds allocable to his share equal the following:

a. In the case of a leased tract, 300 percent of the share of such costs allocable to his interest; or

b. In the case of an unleased tract, 200 percent of the share of such costs allocable to his interest.

D. Any gas or oil owner whose identity and location remain unknown at the conclusion of a hearing concerning the establishment of a pooling order for which public notice was given shall be deemed to have elected to lease his interest to the gas or oil operator at a rate to be established by the Board. The Board shall cause to be established an escrow account into which the unknown lessor's share of proceeds shall be paid and held for his benefit. Such escrowed proceeds shall be deemed to be unclaimed property and shall be disposed of pursuant to the provisions of the Uniform Disposition of Unclaimed Property Act (§ 55-210.1 et seq.).

E. *Any person who does not make an election under the pooling order shall be deemed to have leased his gas or oil interest to the gas or oil well operator as the pooling order may provide.*

*F.* Should a gas or oil owner be a person under a disability, the applicant for a pooling order may petition the appropriate circuit court to appoint a guardian ad litem pursuant to the provisions of § 8.01-261 for purposes of making the election provided for by this section.

~~F~~*G*. Any royalty or overriding royalty reserved in any lease which is deducted from a nonparticipating operator's share of production shall not be subject to charges for operating costs but shall be separately calculated and paid to the royalty owner.

~~G~~*H*. The Board shall resolve all disputes arising among gas or oil operators regarding the amount and reasonableness of well operation costs. The Board shall, by regulation, establish allowable types of costs which may be shared in pooled gas or oil operations.

§ 45.1-361.29. Permit required; gas, oil, or geophysical operations; coalbed methane gas wells; environmental assessment.

A. No person shall commence any ground disturbing activity for a well, gathering pipeline, geophysical exploration or associated activity, facilities or structures without first having obtained from the Director a permit to conduct such activity. Every permit application or permit modification application filed with the Director shall be verified by the permit applicant and shall contain all data, maps, plats, plans and other information as required by regulation or the Director.

B. ~~New~~ *For permits issued on July 1, 1996, or thereafter, new* permits issued by the Director shall be issued only for the following activities: geophysical operations, drilling, casing, equipping, stimulating ~~and~~, producing, *reworking initially productive zones and plugging* a well, or gathering pipeline construction and operation. Applications for new permits to conduct geophysical operations shall be accompanied by an application fee of $100. Applications for all other new permits shall be accompanied by an application fee of $200.

C. ~~Prior~~ *For permits issued prior to July 1, 1996, prior* to commencing any reworking, deepening or plugging of the well, or other activity not previously approved on the permitted site, a permittee shall first obtain a permit modification from the Director. All applications for permit modifications shall be accompanied by a permit modification fee of $100. *For permits issued on July 1, 1996, or thereafter, prior to commencing any new zone completions a permittee shall first obtain a permit* *modification from the Director.*

D. All permits and operations provided for under this section shall conform to the rules, regulations and orders of the Director and the Board. When permit terms or conditions required or provided for under Article 3 (§ 45.1-361.27 et seq.) of this chapter are in conflict with any provision of a conservation order issued pursuant to the provisions of Article 2 (§ 45.1-361.13 et seq.) of this chapter, the terms of the permit shall control. In this event, the operator shall return to the Board for reconsideration of a conservation order in light of the conflicting permit. Every permittee shall be responsible for all operations, activity or disturbances associated with the permitted site.

E. No permit or permit modification shall be issued by the Director until he has received from the applicant a written certification that (i) all notice requirements of this article have been complied with, together with proof thereof, and (ii) the applicant has the right to conduct the operations as set forth in the application and operations plan.

F. A permit shall be required to drill any coalbed methane gas well or to convert any methane drainage borehole into a coalbed methane gas well. In addition to the other requirements of this section, every permit application for a coalbed methane gas well shall include:

1. The method that the coalbed methane gas well operator will use to stimulate the well.

2. a. A signed consent from the coal operator of each coal seam which is located within 750 horizontal feet of the proposed well location (i) which the applicant proposes to stimulate or (ii) which is within 100 vertical feet above or below a coal bearing stratum which the applicant proposes to stimulate.

b. The consent required by this section may be (i) contained in a lease or other such agreement; (ii) contained in an instrument of title; or (iii) in any case where a coal operator cannot be located or identified and the operator has complied with § 45.1-361.19, provided by a pooling order entered pursuant to § 45.1-361.21 or § 45.1-361.22 and provided such order contains a finding that the operator has exercised due diligence in attempting to identify and locate the coal operator. The requirement of signed consent contained in this section shall in no way be considered to impair, abridge or affect any contractual rights or objections arising out of a coalbed methane gas contract or coalbed methane gas lease entered into prior to January 1, 1990, between the applicant and any coal operator, and any extensions or renewals thereto, and the existence of such lease or contractual arrangement and any extensions or renewals thereto shall constitute a waiver of the requirement for the applicant to file an additional signed consent.

3. The unit map, if any, approved by the Board.

G. No permit required by this chapter for activities to be conducted within an area of Tidewater Virginia where drilling is authorized under subsection B of § 62.1-195.1 shall be granted until the environmental impact assessment required by § 62.1-195.1 has been conducted and the assessment has been reviewed by the Department.

§ 45.1-361.30. Notice of permit applications and permit modification applications required; content.

A. Within one day of the day on which the application for a permit for a gas or oil operation is filed, the applicant shall provide notice of the application to the following persons:

1. All surface owners, coal owners, and mineral owners on the tract to be drilled;

2. Coal operators who have registered operation plans with the Department for activities located on the tract to be drilled;

3. All surface owners on tracts where the surface is to be disturbed;

4. All gas, oil, or royalty owners within one-half of the distance specified in § 45.1-361.17 for that type of well, or within one-half of the distance to the nearest well completed in the same pool, whichever is less, or within the boundaries of a drilling unit established pursuant to the provisions of this chapter;

5. All coal operators who have applied for or obtained a mining or prospecting permit with respect to tracts located within 500 feet of the proposed well location or in the case of a proposed coalbed methane gas well location, within 750 feet thereof; ~~and~~

6. All coal owners or mineral owners on tracts located within 500 feet of the proposed well location or in the case of a proposed coalbed methane gas well location, within 750 feet thereof~~.~~*; and*

*7. All operators of gas storage fields certificated by the State Corporation Commission as a public utility facility whose certificated area includes the well location, or whose certificated boundary is* *within 1,250 feet of the proposed well location.*

B. Within one day of the day on which the application for a permit modification for a gas or oil operation is filed, the applicant requesting such permit modification shall provide notice of the application to all persons listed in subsection A of this section who may be directly affected by the proposed activity.

C. Within one day of the day on which the application for a permit for geophysical operations is submitted, the applicant shall provide notice to those persons listed in subdivisions 1, 2 and 3 of subsection A of this section.

D. All notices required to be given pursuant to subsections A, B and C of this section shall contain a statement of the time within which objections may be made and the name and address of the person to whom objections shall be forwarded. Only those persons entitled to notice under subsections A, B, and C of this section shall have standing to object to the issuance of the proposed permit or permit modification for a gas, oil, or geophysical operation as the use may be. *Upon receipt of notice, any person may waive in writing the time and right to object.*

E. Within one day of the day on which the application for a permit is filed, the applicant shall provide notice to (i) the local governing body or chief executive officer of the county, city, or town in which the well is proposed to be located and (ii) the general public, through publication of a notice in at least one newspaper of general circulation which is published in the county, city or town where the well is proposed to be located.

§ 45.1-361.33. Expiration of permits.

All permits issued pursuant to this chapter shall expire twenty-four months from their date of issuance unless the permitted activity has commenced within that time period. *An operator may renew the existing permit for an additional twenty-four months by submitting a written request containing the coal operator's approval and remitting a $250 renewal fee no later than the expiration date.*

§ 45.1-361.35. Objections to permits; hearing.

A. Objections to new or modification permits may be filed with the Director by those having standing as set out in § 45.1-361.30. Such objections shall be filed within fifteen days of the objecting party's receipt of the notice required by § 45.1-361.30. Persons objecting to a permit must state the reasons for their objections.

B. The only objections to permits or permit modifications which may be raised by surface owners are:

1. The operations plan for soil erosion and sediment control is not adequate or not effective;

2. Measures in addition to the requirement for a well's water-protection string are necessary to protect fresh water-bearing strata; and

3. The permitted work will constitute a hazard to the safety of any person.

C. The only objections to permits or permit modifications which may be raised by royalty owners are whether the proposed well work:

1. Directly impinges upon the royalty owner's gas and oil interest; or

2. Threatens to violate the objecting royalty owner's property or statutory rights aside from his contractual rights; and

3. Would not adequately prevent the escape of the Commonwealth's gas and oil resources or provide for the accurate measurement of gas and oil production and delivery to the first point to sale.

D. Objections to permits or permit modifications may be raised by coal owners or operators pursuant to the provisions of §§ 45.1-361.11 and 45.1-361.12.

E. The only objections to permits or permit modifications which may be raised by mineral owners are those which could be raised by a coal owner under § 45.1-361.11 provided the mineral owner makes the objection and affirmatively proves that it does in fact apply with equal force to the mineral in question.

F. *The only objections to permits or permit modifications which may be raised by gas storage field operators are those in which the gas storage operator affirmatively proves that the proposed well work will adversely affect the operation of his State Corporation Commission certificated gas storage field; however, nothing in this subsection shall be construed to preclude the owner of nonstorage strata from the drilling of wells for the purpose of producing oil or gas from any stratum above or below the storage stratum.*

*G. The Director shall have no jurisdiction to hear objections with respect to any matter subject to the jurisdiction of the Board as set out in Article 2 (§ 45.1-361.13 et seq.) of this chapter. Such objections shall be referred to the Board in a manner prescribed by the Director.*

~~G~~ *H.* The Director shall fix a time and place for an informal fact-finding hearing concerning such objections. The hearing shall not be scheduled for less than twenty nor more than thirty days after the objection is filed. The Director shall prepare a notice of the hearing, stating all objections and by whom made, and send a copy of such notice by certified mail, return receipt requested, at least ten days prior to the hearing date, to the permit applicant and to every person with standing to object as prescribed by § 45.1-361.30.

~~H~~ *I.* At the hearing, should the parties fail to come to an agreement, the Director shall proceed to decide the objection pursuant to those provisions of the Administrative Process Act (§ 9-6.14:1 et seq.) relating to informal fact-finding procedures.

Official Use By Clerks

| **Passed By The Senate** | | **Passed By The House of Delegates** | |
|---|---|---|---|
| without amendment | ☐ | without amendment | ☐ |
| with amendment | ☐ | with amendment | ☐ |
| substitute | ☐ | substitute | ☐ |
| substitute w/amdt | ☐ | substitute w/amdt | ☐ |

Date: ______________________ Date: ______________________

______________________ ______________________

Clerk of the Senate Clerk of the House of Delegates