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Clean Air Act - Acid Rain

Stack:	Row:	Section:	Shelf:	Position:
G	12	7	7	3

CAF - Acid Rain

Department of Energy
Washington, DC 20585

THE FAX.
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AND NOTHING
BUT THE FAX



TELECOMMUNICATION MESSAGE

TRANSMITTAL SHEET

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THIS DOCUMENT CONSISTS OF 8 PAGES
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----- (Signature of authorizing official) -----

DATE 9/3/91

TO (Name, Symbol, Extension)

Jeff Holmstead

FROM (Initiator's Name, Symbol, Extension)

Paul Bailey

MESSAGE

8/27/91

DEFINITION OF "REPOWERING" IN THE CLEAN AIR ACT

The new acid rain provisions in the Clean Air Act (CAA) allow up to a 4-year extension of the Phase 2 acid rain compliance deadline for powerplants that repower with a qualifying technology. Section 402(12) of the CAA defines the term "repowering" for the purpose of determining whether a technology qualifies as repowering. (See attached definition.)

Arguably, the language of the definition is susceptible to different interpretations. The most fundamental difference between interpretations is based on whether the language should be read as *requiring* or as *not requiring* replacement of the powerplant boiler.

Because of the possibility of different interpretations, Congressman Ralph Regula (R-OH) sought clarification during last year's CAA debate as to how the definition of "repowering" should be interpreted. Secretary Watkins responded with a letter to Congressman Regula. (See attached letter.) That letter, which was agreed to by EPA and cleared by OMB, states that "the intent of the language is to include in the definition of repowering any technology [meeting three statutory criteria] . . . For this class of technologies, boiler replacement is not intended to be a precondition to being considered a repowering technology." The letter went on to say "the Administration does not believe that further clarification of the definition is required." In other words, from the standpoint of the Administration, there was no question that *the definition should be interpreted as not requiring boiler replacement.*

The Administration position expressed in Secretary Watkins' letter has not been challenged by anyone in the Administration until EPA recently put forth a different interpretation. In its draft proposed acid rain rule (dated 6/21/91), EPA has interpreted the definition of repowering as *requiring replacement or "substantial modification"* of the boiler. The interpretation is contrary to the Administration position that boiler replacement, or even substantial modification, is not required so long as the three statutory criteria (multi-pollutant control, efficiency improvement, and waste reduction) are satisfied.

DOE has expressed its objection to the new EPA interpretation. Because this matter involves a disagreement over legal interpretation, DOE has proposed that the Department of Justice (DOJ) render an opinion concerning the interpretation of the language. Former EPA General Counsel Don Elliott responded by letter to DOE's proposal. (See attached letter.) The Elliott letter describes a "process agreed upon within the Administration" whenever another agency disagrees with EPA. The process involves the other agency appealing the views of EPA legal staff to the EPA General Counsel for an opinion. Following that, the EPA General Counsel's opinion can then be appealed to DOJ "on the ground that the EPA opinion is not legally defensible."

First, DOE does not agree with the process described in the Elliott letter. Second, putting that concern aside, the Elliott process is not applicable to resolution of the repowering issue because the Administration set forth its legally defensible interpretation of "repowering" over one year ago in Secretary Watkins' letter to Congressman Regula. *If EPA now believes it should propose a rule that differs from the Administration position, the agency should demonstrate why the Administration position is not legally defensible. Otherwise, the Administration position should be adopted by EPA in its proposed rule.* This is in accordance with Administrator Reilly's letter to CEA Chairman Boskin which commits EPA to "adopt as the basis for regulatory and administrative actions the position reached by the Administration during the clean air debate."

**Definition of Repowering in
Section 402(12) of the Clean Air Act**

"(12) The term 'repowering' means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990. Notwithstanding the provisions of section 409(a), for the purpose of this title, the term 'repowering' shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.



The Secretary of Energy
Washington, DC 20585

July 2, 1990

The Honorable Ralph Regula
U.S. House of Representatives
Washington, D.C. 20515

Dear Congressman Regula:

Thank you for apprising me of your intent to clarify in the Clean Air Act amendments that clean coal technologies which simultaneously control multiple pollutants are eligible for the extension of the Phase II compliance deadline. You specifically focused on the eligibility of technologies not requiring boiler replacement for consideration as repowering technologies.

The Administration worked closely with the Senate leadership in developing the definition of repowering which was adopted in S. 1630 and was thereafter incorporated into H.R. 3030. The intent of the language is to include in the definition of repowering any technology capable of controlling multiple combustion emissions simultaneously, so long as the two criteria specified (i.e., increased boiler efficiency and significantly greater waste reduction) are met. For this class of technologies, boiler replacement is not intended to be a precondition to being considered a repowering technology. Accordingly, the Administration does not believe that further clarification of the definition is required.

The Department is aware of two projects in the Clean Coal Technology Program which control multiple pollutants and which may meet the remaining two preconditions described above. These projects, neither of which requires boiler replacement, are the Low NO_x/SO₂ Burner Retrofit for Utility Cyclone Boilers Project and the Advanced Slagging Combustor Utility Demonstration Project. Both involve replacement of burners with sophisticated slagging combustors for NO_x control and use of alkaline reagents for SO₂ control. Data for these two technologies responsive to the questions in your letter are included in the enclosed fact sheets. Please note that the definition of

repowering in both H.R. 3030 and S. 1620 prescribes that final determinations regarding the applicability of the repowering definition to technologies like these will be made on a case-by-case basis by the Environmental Protection Agency in consultation with the Department of Energy.

The Office of Management and Budget has advised that there is no objection to the submission of this report from the standpoint of the President's program.

Thank you for your inquiry on this important matter.

Sincerely,


James D. Watkins
Admiral, U.S. Navy (Retired)

Enclosures



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

AUG 16 1991

OFFICE OF
GENERAL COUNSEL

Ms. Linda Stuntz
Deputy Under Secretary for
Policy, Planning and Analysis
Department of Energy
Washington, D.C. 20585

RE: Issuance of Legal Opinion Regarding Definition of
"Repowering" Under Title IV of the Clean Air Act

Dear Linda:

Bill Rosenberg has asked that I respond to Paul Bailey's memorandum dated August 12, 1991, suggesting the need to obtain a legal opinion from the Environment and Natural Resources Division of the Department of Justice regarding the definition of "repowering" in section 402(12) of the Clean Air Act. DOE disagrees with the legal position reflected in EPA's draft acid rain rules that a qualifying Phase II repowering technology must involve substantial modification or replacement of a boiler.

Under the process agreed upon within the Administration, if another agency disagrees with the initial legal views regarding the interpretation of an environmental statute administered by EPA as expressed by the staff of EPA's Office of General Counsel, the General Counsel will provide a final legal opinion on the matter. I have always thought it useful to get the benefit of DOE's and the other agencies' legal views before rendering a final opinion, and I anticipate that my successor will continue this practice. After the EPA General Counsel or his designee has issued his opinion, the general counsel of another agency can decide whether to appeal that opinion to the Office of Legal Counsel at the Department of Justice on the ground that the EPA opinion is not legally defensible.

EPA plans to follow the process outlined above on the matter of the repowering definition, as well as on the issue regarding the applicability of NOx emission limitations under section 407

- 2 -

to compensating units that become affected units under section 404 by virtue of the reduced utilization provisions of section 408(c)(1)(B). This office will prepare those opinions in the near future.

Sincerely,



E. Donald Elliott
Assistant Administrator
and General Counsel

cc: John Schmitz, White House Counsel's Office
Barry Hartman, Acting Assistant Attorney General,
Department of Justice
David Rivkin, Department of Energy
Ray Ludwiszewski
Bill Rosenberg



Department of Energy

Washington, DC 20585

CRA - Acid Rain

September 4, 1991

MEMORANDUM TO:

Art Fraas
Teresa Gorman
Jeff Holmstead

FROM:

Paul Bailey

Paul Bailey

SUBJECT:

Clean Air Act Definition of "Repowering"

Enclosed is a copy of what I faxed to you late yesterday. It is a brief background paper about the definition of "repowering." It is not a legal analysis, but merely summarizes DOE's view of the issue. Note that the paper was written before we received EPA's recent memo on repowering and NO_x.

cc: Linda Stuntz
Howard Gruenspecht

8/27/91

DEFINITION OF "REPOWERING" IN THE CLEAN AIR ACT

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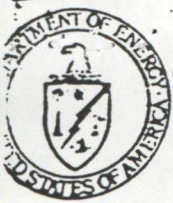
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Washington, DC 20585

July 2, 1990

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Sincerely,


James D. Watkins
Admiral, U.S. Navy (Retired)

Enclosures



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

AUG 16 1991

OFFICE OF
GENERAL COUNSEL

Ms. Linda Stuntz
Deputy Under Secretary for
Policy, Planning and Analysis
Department of Energy
Washington, D.C. 20585

RE: Issuance of Legal Opinion Regarding Definition of
"Repowering" Under Title IV of the Clean Air Act

Dear Linda:

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EPA plans to follow the process outlined above on the matter of the repowering definition, as well as on the issue regarding the applicability of NOx emission limitations under section 407

to compensating units that become affected units under section 404 by virtue of the reduced utilization provisions of section 408(c)(1)(B). This office will prepare those opinions in the near future.

Sincerely,

A handwritten signature in dark ink, appearing to read "E. Donald Elliott". The signature is fluid and cursive, with the first letters of the first and last names being capitalized and prominent.

E. Donald Elliott
Assistant Administrator
and General Counsel

cc: John Schmitz, White House Counsel's Office
Barry Hartman, Acting Assistant Attorney General,
Department of Justice
David Rivkin, Department of Energy
Ray Ludwiszewski
Bill Rosenberg



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

OCT 3 1991

MEMORANDUM

SUBJECT: Acid Rain Rules

OFFICE OF
AIR AND RADIATION

FROM: William Rosenberg *WR*
Assistant Administrator
for Air and Radiation

TO: William Reilly
Michael Boskin
Art Fraas
Robert Grady
C. Boyden Gray
Allan Hubbard
Roger Porter
Linda Stuntz

The attached letter conveys EDF and NRDC support for the Title IV Acid Rain Rules with monitoring systems as accurate as possible to assure a 10 million reduction and a credible trading system.

This offers an opportunity to have the leaders in the environmental community endorse the principle regulatory reform initiative of the President by testifying publicly that these rules are "a faithful effort to develop a market-based system that delivers on environmental objectives."

Attachment

MAJOR CLEAN AIR ISSUES

ACID RAIN RULES:

Repowering:

- In the definition of repowering, replace "substantial modifications to increase efficiency, reduce waste, and control multiple pollutants," with the words "substantial changes necessary to increase efficiency, reduce waste and control multiple pollutants."

Monitoring:

- Return to EPA, CEA, OPD, OMB, and DOE agreement on missing data, and relative accuracy test.
- Allow EPA to include a bias test, but include a 5 percent relative accuracy test exemption for the bias test.

NOx Controls on Compensating Phase II Units

- Compensating Phase II units are not required to meet lower NOx limits until such units are affected by the specific NOx control provisions under Section 407.

Strict, Joint and Several Liability

- EPA must delete draft regulatory provision requiring strict, joint, and several liability among majority and minority utility owners.

OTHER UTILITY RELATED RULES

WEPCO

- EPA must promulgate the final WEPCO rule as proposed by December 31 1991.

NOx Control Limits for Utility Boilers

- EPA draft proposal on NOx must be sent to OMB by October 30th.
- The definition of low NOx burner technology cannot include overfired air.
- EPA must issue the final rule by the May 1992 statutory deadline.

BACT

- Core criteria does not include the most stringent technology.
- Permitting authority will make the decision on the weighing of the statutory criteria.

Permitting

- Minor permit amendment should go forward as proposed with exception that longer notice period will be accommodated.

To: Bill Rosenberg

From: NRDC - Washington, DC

10-3-91 12:44pm p.2

Natural Resources Defense Council / Environmental Defense Fund

1350 New York Ave., NW Washington, DC 20005 (202) 783-7800 / 357 Park Ave. South New York, NY 10010 (212) 505-2100

October 3, 1991

Honorable William K. Reilly
Administrator
U.S. Environmental Protection Agency
401 M Street, SW Room 1200
Waterside West Building
Washington, DC 20460

Dear Bill:

We understand that the Administration is completing its review of draft regulations to implement the acid rain provisions of the 1990 Amendments to the Clean Air Act and that disputes continue on a number of key issues. We are writing to emphasize the overwhelming importance of several of these issues.

1. DEFINITION OF REPOWERING:

The Act provides for a 4-year extension of emissions reduction compliance dates from 2000 to 2004 for "repowering" projects that involve the replacement of existing generating units. Industry and some government agencies have argued for months that EPA should ignore the statutory restriction of this extension provision to projects that involve the actual replacement of existing units. We understand these efforts are continuing.

Any interpretation that would make the 4-year repowering extension available to non-replacement units not only would be illegal, it would frustrate the Administration's promise to carry out an acid rain program that ensures 10 million tons of SO₂ reductions by the year 2000. A broad repowering interpretation would pave the way for numerous 4-year extensions of the year 2000 compliance date, causing the program to miss the President's 10 million ton reduction commitment by millions of tons.

2. BIAS TEST FOR UTILITY MEASUREMENT SYSTEMS:

The heart of the allowance trading program proposed by the President and endorsed by our groups is the statutory requirement for comprehensive and accurate emission monitoring information. It should be a given that EPA's rules for monitoring systems must prohibit any measurement bias that would underreport emissions. However, we understand that serious

To: Bill Rosenberg

From: NRDC - Washington, DC

10-3-91 12:44pm p.3

2

consideration is actually being given to exemptions that would eliminate requirements for bias correction for monitoring systems that are within 5-10% of reference values. There is absolutely no technical or policy justification for this remarkable proposal. It would encourage the design and calibration of systems that are deliberately biased to underreport emissions.

Such an exemption would attack the central pillar of the allowance trading system: that it is based on honest emissions information. The rumored bias exemption would be the equivalent of a proposal to allow used car dealers to roll back odometers by 5-10% or grocers to overstate product weights by 5-10%.

3. MISSING DATA PROCEDURES:

A major reform in the Administration acid rain proposal is the requirement that when emission monitoring data are not collected, EPA is required to calculate emissions based on presumed uncontrolled rates. This provision is wholly consistent with the market incentive structure of the acid rain program: a plant operator will always be better off (i.e., consume fewer allowances) by collecting valid data rather than failing to collect such data. This built-in incentive system is crucial to assure proper operation of systems whose performance is linked to daily operation and maintenance decisions at the plant level.

EPA's draft rules would fill in extended data gaps with default values based on maximum recorded values during prior periods. Under the draft structure, as data gap lengths increase and as cumulative amounts of missing data increase, the plant operator must use the maximum values from longer reference periods to fill in the missing data. This approach establishes the proper incentives to maximize monitor performance: poorer performance results in larger required fill-in values because the maximum value in the prior 365 days will typically be larger and will never be smaller than the maximum value in the prior 90 days.

However, we understand that the Administration is considering replacing the requirement for use of the maximum value with the 90th percentile value from prior periods. This change would introduce a fatal flaw into the entire proposed missing data procedure that would turn the proper monitoring incentive objective on its head.

Unlike the maximum value method, any percentile-based approach will create incentives for plant operators not to collect monitoring data! This will occur whenever the 90th percentile value in the prior 90 days is larger than the 90th percentile value in the prior 365 days (a frequent occurrence). Whenever plant calculations show the longer period results in a lower fill-in value, operators would be presented with a direct incentive to not operate their monitors so as to kick themselves into the 365 day "look-back" period. Moreover, the plants that could take the greatest advantage of this perverse approach are the plants with the worst monitor availability performance levels.

The Agency cannot possibly rely on command and control policing methods to eliminate the monitoring abuses that would occur under a system whose rules would reward operators for not monitoring. The percentile-based approach cannot be reconciled with the goal of achieving full and honest emissions measurement.

To: Bill Rosenberg

From: NRDC - Washington, DC

10-3-91 12:45pm p.4

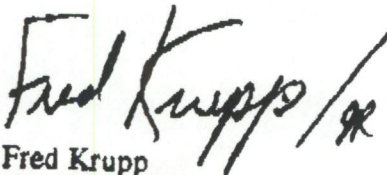
3

We have been glad to praise the President's policy initiatives on acid rain and we want to work with the Administration to develop rules that will inspire confidence in the acid rain program's market-based approach. Much excellent work has gone into development of the critical implementing rules needed to turn the President's policy promise into an environmental reality.

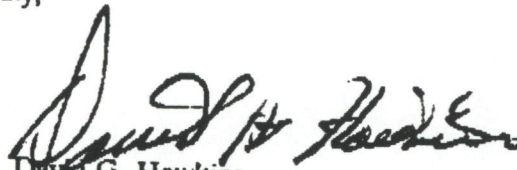
The issues we have highlighted in this letter are central to the success of the acid rain program. The way these crucial issues are resolved will determine whether our groups can laud the Administration's forthcoming rules as a faithful effort to develop a market-based system that delivers on environmental objectives.

If there is any way that we can help the Administration make the right call on these rules we would be happy to meet with you or others at your convenience.

Sincerely,



Fred Krupp
Executive Director
Environmental Defense Fund



David G. Hawkins
Senior Attorney
Natural Resources Defense Council

August 12, 1991

MEMORANDUM

TO: Jeff Holmstead
Teresa Gorhman

FROM: ^{DB} David B. Rivkin, Jr.

RE: NOx Requirements Under the Acid Rain Program of the
Clean Air Act

I. Introduction

Section 407 in Title IV (Acid Deposition Control Program) of the 1990 Clean Air Act Amendments ("CAAA" or "Act") requires EPA to promulgate nitrogen oxides (NOx) emission limits for boilers that become affected units pursuant to specified provisions of the Act setting sulfur dioxide (SO2) requirements. EPA also must issue regulations to implement the options provided by Section 407 to achieve NOx emissions reductions.¹

It is highly doubtful that EPA will meet the statutory target date of May 15, 1992 for issuing a final NOx control rule. Currently, the agency is evaluating issues concerning the substantive requirements of the NOx control program through the Acid Rain Advisory Committee ("ARAC") process. Recently, EPA proposed certain NOx procedural rules in the draft permits regulation that it issued under Title IV of the CAAA.² In that regulation, EPA also proposed to subject Phase II compensating

¹ In that regard, EPA must issue regulations to implement provisions of Section 407 allowing the use of less stringent alternative emission standards for individual units, extensions of the January 1, 1995 deadline for complying with NOx emission requirements, and compliance through averaging NOx emissions among units.

² See draft sections 72.46 -- 72.48 of the proposed Acid Rain Permits Regulation (40 CFR Part 72).

units to applicable Section 407 NOx requirements where Phase I units reduced utilization to comply with SO2 emission limitations.³

Before the substantive and procedural requirements of the NOx component of the acid rain program can be fully developed, it is necessary to resolve the issue of whether the Act establishes presumptive emissions rates for tangentially-fired and dry-bottom wall-fired boilers, based on the maximum reductions achievable using low-NOx burner technology.⁴ In addition, EPA needs to reconsider the statutory grounds for its recent proposal imposing Section 407 NOx requirements on compensating units in reduced utilization cases. Decisions on both of these matters will fundamentally affect the implementation of the NOx program.

II. Conclusion

For the reasons discussed below, we believe that Congress prescribed specific numerical limits as presumptive standards for tangentially-fired and dry-bottom wall-fired boilers, based on the reductions achievable using low-NOx burners. We also maintain that Congress did not intend for the NOx rate limitations to be triggered when Phase I units reduce utilization to comply with SO2 emission tonnage limitations. Finally, we feel that some of the NOx procedural rules that EPA has proposed in its draft permits regulation are troublesome because they fail to reflect the relevant congressional intent and the underlying purpose of the NOx program or the consensus positions reached by ARAC's permitting subcommittee.

III. Discussion

A. Section 407(b)(1)

The language and legislative history of the CAAA manifest a congressional intent to establish, based on the capabilities of low-NOx burner technology ("LNB"), presumptive NOx emission rates for certain affected units in Phase I of the SO2 control program.

Specifically, Section 407(b)(1) of the Act directs EPA to issue maximum annual NOx emissions limits, effective January 1, 1995, for tangentially-fired and dry-bottom wall-fired utility boilers not to exceed 0.45 and 0.5 lb/mmBtu respectively. Significantly, EPA may set a less stringent rate for those boilers if the listed rates cannot be met using LNB technology. The fact that this provision gives EPA the discretion to raise the CAAA specified emission

³ See draft section 72.43.

⁴ I understand that EPA's Office of General Counsel will be soon issuing an opinion that sets forth the Agency's interpretation of the language in Section 407(b)(1).

limits if they cannot be attained using LNB controls suggests that those levels were calculated to effect reductions considered achievable using that technology. The language in the other provisions of Section 407 supports this interpretation and confirms that the provision was not intended to authorize EPA to set lower rates based on the availability of more stringent non-LNB technology.

Indeed, while Section 407(b)(2) authorizes EPA to set more stringent limits for tangentially-fired and dry bottom wall-fired boilers by January 1, 1997, this power can be exercised only if the Agency determines that more effective LNB technology is available.⁵ Clearly, the subsequent availability of more advanced LNB technology would be an irrelevant consideration were the (b)(1) limits to be based initially on more stringent non-LNB control technologies. It is evident from provisions (b)(1) and (b)(2), read together, that Congress intended to restrict EPA to requiring control technology no more stringent than LNB technology.

This interpretation is reinforced by the requirements of Section 407(d) for establishing unit-specific alternative emission limitations. That provision allows the acid deposition control permitting authority to set a less stringent emission standard for an individual Phase I unit upon a showing that the unit could not meet the (b)(1) standard using LNB technology. Section 407(d) emphasizes that a unit would not be required to install any additional equipment beyond low NOx burners. If (b)(1) rates were based on technologies more stringent than LNB technology, few units if any, that used low-NOx burners would be capable of complying with those rates. This would not appear to be a result that Congress intended, given the fact that both the specified limits deviations, whether up or down, therefrom, and compliance options set forth in Section 407 all focus on LNB controls as the means for reducing NOx emissions. It would not be an exaggeration to say that the LNB technology and its capabilities permeate the entire NOx control scheme, set forth in the CAAA.

Indeed, the legislative history of Section 407 buttresses this view. The Joint Explanatory Statement of the Committee of Conference provides that "NOx reductions from existing units mandated under Section 407 are to be accomplished by use of conventional, available burner technology ("low-NOx burners")."

It should be stressed that this issue has to be resolved as expeditiously as possible. The reason for the haste is that group 1 units will be very hard-pressed to retrofit even LNB technology within the tight time constraints set by the statute. The Act

⁵ To be sure, the more stringent limits would not apply to Phase I affected units which would already have had to meet the first set of NOx emission limits.

requires Phase I tangentially-fired and dry bottom wall-fired boilers to install low-NOx burners by January 1, 1995. The burners must be individually designed and fabricated, which I understand takes about twelve months. Even if EPA issues a final rule by the May 15, 1992 deadline, utilities will have only four outage periods to retrofit low NOx burners - spring and fall 1993 and spring and fall 1994.⁶ If issuance is delayed, the installation schedule would be compressed into three or fewer periods. This would probably cause back-ups in the schedules for supplying, designing and installing the burners, as well as system reliability problems (by forcing multiple units out of service at the same time).

II. NOx Requirements Triggered by Reduced Utilization

In its draft permits regulation for the acid rain program, EPA has proposed a rule to implement the reduced utilization compliance option provided in Section 408(c)(1)(B) of the Act.⁷ Under the proposed rule, if a Phase I unit intends to reduce utilization below its baseline in any calendar year to comply with its emission reduction obligations under the program, the utility must file a reduced utilization compliance plan and designate any non-Phase I unit that provided compensating generation (unless the Phase I unit can demonstrate energy conservation or improved unit efficiency in accordance with the Act and EPA's rules). In turn, a designated compensating unit would become an affected unit for Phase I, subject to all applicable SO₂ and NOx emission limitations under Title IV. Failure to submit a reduced utilization plan in accordance with the rule would constitute a violation of the Act, potentially subjecting the designated representative, and the owners and operators of the Phase I unit to criminal, civil and administrative penalties. Significantly, under the proposed rule, a utility would be deemed to have violated the Act for failing to submit a plan, if EPA determined after-the-fact that the utility reduced utilization as a "method of compliance" with Phase I emission requirements.⁸

⁶ An outage period refers to a time period when a utility can take down a certain portion of its generation capacity, so as to perform needed maintenance and install any new equipment that might be required. Utilities usually strive to ensure that no more than a certain percentage of generating capacity is down -- otherwise serious reliability problems emerge and brownouts are possible.

⁷ See Section 72.43.

⁸ EPA would determine whether the reduced utilization represented a method of compliance based on seven criteria and unspecified "other factors." EPA did not indicate in its proposal what weight it would attach to the respective factors in its determinations. Nor is it clear whether EPA would analyze these

Yet, whether underutilization is planned or unplanned, the statutory language does not provide support for applying Section 407 NOx requirements to compensating units. As EPA itself notes in the preamble to its draft regulation, Section 408(c)(1)(B) "does not state explicitly that these compensating units become affected under section 407." In fact, the express references to Section 407 in two other places in the provision make conspicuous the omission of any reference to Section 407 in that part of section 408(c)(1)(B) which characterizes the status of compensating units.

To be sure, EPA claims that the Act's use of the phrase "to be deemed an affected unit under Section 404" is a "short-hand approach" for expressing the applicability of Section 407 requirements because units that become affected under Section 404 also are affected under section 407. However, Section 407(a) only states that a unit becomes subject to the NOx limitations on the date that it "becomes an affected unit pursuant to sections 404, 405, 409" Specifically, that provision does not refer to units that are deemed to be affected units pursuant to section 408(c)(1)(B).

It also is noteworthy that Congress defined more narrowly the status of a compensating unit in Section 408(c)(1)(B) than that of a substitute unit in Section 404(c). Whereas in 408(c)(1)(B), a compensating unit "shall be deemed an affected unit under section 404, subject to all of the requirements for such units under [Title IV]," a substitute unit described in Section 404(c) "shall be deemed affected under [Title IV]." Accordingly, the requirements under Title IV to which a compensating unit is subject are those related to the implementation and enforcement of section 404, not Section 407.

Most importantly, the method of compliance described in Section 408(c)(1)(B) has significance only with respect to the SO2 program. The section applies where the owner or operator of an affected unit proposes to comply "by reducing utilization of the unit as compared with its baseline." The baseline is the utilization level that the Act multiplies by 2.5 lbs/mmBtu to determine the Phase I SO2 allowance allocations. A unit can meet its Phase I SO2 emission allowance and tonnage limitations by keeping its emission rate above 2.5 lbs/mmBtu and reducing its utilization below its baseline. By contrast, the section 407 NOx requirements are emission rate limitations. Reducing utilization below baseline is not a method of compliance with the emission rate limits of Section 407; a unit's emission rate is independent of its baseline or any other utilization level.

factors with a benefit of hindsight or whether it would analyze the reasonableness of the prospective determination made by the utility involved.

Finally, requiring compliance with NOx requirements where reduced utilization is deemed a method of compliance would not be advisable for economic and policy reasons. Imposing such limits based on an after-the-fact EPA determination of failure to file a plan could severely disrupt utility planning and investment decision-making, interfere with electric reliability, and be costly for utilities and their ratepayers. Even imposing NOx requirements on a prospective basis would be onerous, given the difficulties and costs that utilities will face in scheduling outages for installation of low-NOx burners to meet Section 407(b) rate limitations.

III. Proposed NOx Procedural Requirements

In its draft permits regulation, EPA has proposed some NOx procedural rules to implement the provisions of Section 407 allowing the use of less stringent alternative emission limitations, extensions of the January 1, 1995 deadline for complying with emission limits, and compliance through averaging emissions among units. The general approach that the draft rules take is to provide maximum flexibility consistent with the impact that the respective NOx compliance options would likely have on the environment. Accordingly, the greatest flexibility is provided in the case of the emissions averaging option, while more stringent requirements are established for the approval of alternative emission limitations.⁹

However, in some respects, the proposed NOx procedural rules are inconsistent with or not authorized by the Act. Also, certain rules fail to reflect consensus positions reached by ARAC's permitting subcommittee.

First, the draft rules include operating conditions that would interfere with prudent boiler operation. For example, the draft rules on alternative emission limits require that compliance plans include "design, equipment work practice and operational standards that will apply to the unit, in accordance with [the NOx control rule]," [Section 72.47(d)(2)(vi)]. The plan also must include "a vendor certification that there is no adjustment to the equipment that can be done such that the unit would be able to achieve the

⁹ Emissions averaging petitions are the most environmentally neutral of the three options because the petitions must ensure that the actual annual emission rate in lbs/mmBtu averaged over the units subject to the plan is less than or equal to the Btu-weighted average annual emission rate for the units if they had been operated in compliance with otherwise applicable emission limits. Deadline extension plans allow for higher emission rates than the generic limits for a limited period. Alternative emission limitation plans allow for a permanent limit in excess of required limits.

applicable limit [of the NOx control rule]." However, the Act appears to contemplate the use of generally accepted standards for prudent boiler operation.

In the case of emissions averaging plans, §407(e) requires that operating conditions pertinent to using emissions averaging be specified in the units' operating permits. While ARAC members agreed that changes in operating conditions could necessitate revising the permit, the members believed that the permitting authority should require notification only when operating changes would jeopardize the ability of the unit(s) to meet the applicable annual average emission limit. No detailed operational standards were anticipated. Draft Section 72.46(c)(14) would require demonstration of compliance "with operating conditions specified in the plans."

Second, certain rules include requirements that are not authorized by the Act. The draft rules require that during a demonstration period for an alternative emission limit, a unit must comply with an "interim emissions limitation and operating conditions" defined by the agency [Section 72.47(d)(1)(iv),(v)]. Section 407(d) does not authorize the establishment of "interim" emission limits and operating requirements. The provision states that the permitting authority "shall issue an operating permit . . . that permits the unit during the demonstration period. . . to emit at a rate in excess of the applicable emission rate." The statutory requirement that the owner or operator "properly install" and "properly operate" appropriate NOx control technology during the demonstration period will ensure that NOx emissions are minimized, consistent with prudent boiler operation.

Also, the draft rule on the 15 month compliance extension of the January 1, 1995 deadline requires the establishment of "an emissions limitation and operating conditions" that would apply during the extension period [72.48(d)(2)(ii)(A)]. However, the act authorizes a compliance extension of 15 months in order to enable the retrofit of NOx control technology, and does not require EPA to establish compliance requirements during that period.

Third, EPA has proposed certain rules that are inconsistent with statutory requirements. For example, the draft rules require utilities to submit an alternative emission limit application 90 days before the conclusion of the required 15-month minimum demonstration period [§72.46(c)(1)(ii)]. Since the review and analysis of data collected during the demonstration will be needed before the results of the demonstration program can be submitted, the requirement of the draft rules to submit an analysis after 12 months, in effect, compresses the demonstration to a period of 8-10 months. Instead, the rules should provide for a minimum 15-month demonstration period and for a brief period afterwards to review and analyze the data collected and to submit the application.

Fourth, the information requirements to support an alternative emission limit application call for confidential and unnecessary documentation such as copies of solicitations, purchase orders, design engineering, or construction contracts [72.47(d)(1)(ii)(B)(3)]. More limited information would fulfill the same objectives: vendor certifications regarding technological capabilities, chronologies regarding contracting efforts, information on vendor guarantees).

Fifth, some of the drafted provisions do not reflect consensus positions reached by ARAC's permitting subcommittee. Section 407(e) provides for emission rate averaging, not for calculations in tons-per-year, as suggested in certain provisions of the draft emission averaging rules [§72.46(d)(3)]. While ARAC's permitting subcommittee agreed that no minimum operating period should be required before one could apply for an alternative emission limit, the draft rules require six months of data to submit an application [§72.47(b)(2)(i)].

I believe the drafted procedural rules need to be re-examined in terms of the overall implementation of the NOx control program. In general, the procedures should be streamlined in keeping with the straight-forward directives that Congress provided in Section 407.

THE WHITE HOUSE

WASHINGTON

April 6, 1990

MEMORANDUM FOR THE FILE

FROM: JEFFREY R. HOLMSTEAD *JRH*
ASSISTANT COUNSEL TO THE PRESIDENT

SUBJECT: Significant Reductions in SO₂ and NO_x; A Cap on
SO₂ Emissions; A Date Certain to Accomplish these
Objectives; and a Smoothly Functioning Allowance
Trading System

I have reviewed above-referenced document, which will be used in on-going discussions regarding the President's proposed amendments to the Clean Air Act. No further action is necessary.

WHITE HOUSE CORRESPONDENCE TRACKING WORKSHEET

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Subject: Letter to Rep. Philip Sharp stating 4 most
important components of the acid rain protocol ① significant
reductions in SO₂ and NO_x ② a cap on SO₂ emissions ③ a date
certain to accomplish these objectives ④ a smoothly functioning
allowance trading system

ROUTE TO:

ACTION

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NOTES: JOHN - this is the

stuff we gave Sharp
last week. Main focus
is trading, not the
tax and subsidy question.

Best

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ENVIRONMENTAL DEFENSE FUND

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March 26, 1990

Representative Philip R. Sharp
Chairman, Subcommittee on Energy and Power
Committee on Energy and Commerce
U.S. House of Representatives
2217 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Sharp:

The Environmental Defense Fund is pleased to comment on your draft acid rain proposal. In general, the Environmental Defense Fund believes that the four most important components of any acid rain proposal are (1) significant reductions in SO₂ and NO_x emissions, (2) a cap on SO₂ emissions, (3) a date certain to accomplish these objectives, and (4) a smoothly functioning allowance trading system.

While your proposal offers several improvements in H.R. 3030, specifically by narrowing the exemptions for those using clean coal technologies, we believe it is important to comment on a number of problems that could undermine the workability and effectiveness of your proposal. Although we believe these problems were not intended, they should be addressed to achieve the greatest possible reductions in acid rain pollution. Enclosed are extensive comments and suggestions on your draft proposal.

Our comments cover a wide range of areas, but they focus primarily on the auction provision, the allocation of allowances, and the provision on Independent Power Guarantees. On each of these major issues, we have concerns about the workability of the proposal and we offer a number of suggestions to improve the draft.

1616 P Street, NW
Washington, DC 20036
(202) 387-3500

1405 Arapahoe Avenue
Boulder, CO 80302
(303) 440-4901

5655 College Avenue
Oakland, CA 94618
(415) 658-8008

1108 East Main Street
Richmond, VA 23219
(804) 780-1297

128 East Hargett Street
Raleigh, NC 27601
(919) 821-7793

Chairman Philip R. Sharp
March 26, 1990

Because the Full Committee will consider Title V of H.R. 3030 in the next week or so, we request a meeting with you to discuss our concerns. Please let me know when we can schedule an appointment.

Once again, thank you for considering our views.

Sincerely,

William J. Roberts
Legislative Director

cc: Honorable John D. Dingell
Honorable Norman F. Lent
Honorable Henry A. Waxman
Honorable Edward R. Madigan
Honorable Carlos J. Moorhead

COMMENTS OF THE ENVIRONMENTAL DEFENSE FUND
ON THE SHARP AMENDMENT TO TITLE V OF H.R. 3030
3/7/90 DRAFT

The following comments and questions address the 3/7/90 draft acid rain amendment. In general, the Environmental Defense Fund believes that the four most important components of any acid rain provision are (1) significant reductions in SO₂ and NO_x emissions, (2) a cap on SO₂ emissions, (3) a date certain to accomplish these objectives, and (4) a smoothly functioning allowance trading system. Although the environmental benefits of an emissions cap are obvious, the important environmental benefits of the allowance trading system may be less clear.

If allowed to work smoothly and efficiently, the allowance trading system can achieve substantial environmental benefits at lower cost. Most analyses indicate up to 75 percent in cost savings. Under the allowance system, affected units have an incentive to lower emissions beyond those required by law in order to profit from the sale of unused allowances. The greater the demand for allowances, the greater the incentive for affected units to reduce emissions below the legal limit.

However, the viability of allowance trading benefits is dependent largely on an unencumbered market. To the extent the marketplace is clouded with uncertainties or incentives that work counter to the free flow of allowances, the incentive for emissions reductions below the legal limit will be lost. Further, the cost savings and cost-sharing inherent in a smoothly functioning market would not be produced.

It is with an eye toward achieving greater certainty and clarity in the trading system that we submit these comments. We hope that they help in your consideration of this legislation.

Page 10, lines 15-23. COMPETITION PROVISION.

Although this subparagraph is designed to ensure fully competitive markets for allowances, we fear it could have the opposite effect. By establishing separate regulations defining "discrimination," "impede access," and "reasonably transferable," we will likely place a damper on transactions and encourage hoarding. Before an allowance sale, an affected unit will be required to measure the sale against these legal requirements. As you know, the law governing price "discrimination" in antitrust law is anything but clear, and the uncertainty under a new "discrimination" standard is likely to be more cloudy. Similar problems are likely to arise with terms like "impede access" and "reasonably transferable."

If there is genuine concern over anticompetitive misconduct, the Administrator is free to add such regulations under the broader language of subparagraph 503(b)(1)(A). Making those regulations mandatory is confusing and unnecessary. We recommend striking this provision.

Page 11, line 24. ALLOWANCE REGULATION REVISIONS.

We recommend changing "shall" to "may" on this line. Once again, the trading system will suffer if the rules of trading must be amended every few years. Affected units will be undertaking long term planning following enactment, and their ability to accurately predict the value of their allowances will be a major determinant of their efforts to achieve greater than needed emissions reductions as well as their ability to achieve cost savings from trading among a system's own affected units. Obviously, a mandatory revision of the trading allowance system half way between 1992 and 2000 will have a chilling effect on long term planning during this period. By making our recommended change, any revisions would be discretionary. The Administrator is free to step in if there are major problems, but he need not do so. Although this change will leave some uncertainty, we believe a well run trading system will and should be left alone.

Page 14, lines 12-16. AFFECTED UNIT REPORTS.

Why is it necessary for affected units to file annual reports detailing their reasons for holding allowances? To function smoothly, the participants in the allowance market must be free to make decisions based on their operating plans as well as changing circumstances. If forced to explain the basis for these decisions publicly, we believe allowance holders will be discouraged from participating fully in the market. We recommend striking the references to those holding allowances and, instead, we suggest that EPA be required to maintain up-to-date records of allowances held by affected units and make this information available to the public.

Page 15, lines 6-8. USING FUTURE ALLOWANCES FOR PAST EMISSIONS.

Generally speaking, we support this provision because it ensures that speculative future emissions reductions are not used to allow present emissions increases. However, this provision may conflict with the excess emissions offset provision on page 54, lines 14-25. Under the offset provision, the Administrator must reduce the allowances issued in the current or future years to account for excess emissions occurring in the previous year. We believe the sentence on page 15, lines 6-8 should be clarified so it does not undercut the Administrator's authority to reduce allowances under the excess emissions offset provision.

Page 16, line 6. EXTINGUISHED ALLOWANCES.

What does the term "extinguished" mean? Is this sentence needed? Doesn't this provision conflict with the 8.9 million ton limit if, for example, the total tonnage exceeds 8.9 million tons and allowances must be withdrawn to maintain the cap?

Page 17, lines 8-11. REGULATIONS FOR HOLDING ALLOWANCES.

Although it makes sense to require that transactions be recorded pursuant to EPA regulations, we do not understand why this prohibition also applies to those holding allowances. Except for the reporting requirements, which we have discussed earlier (see comments on page 14, lines 12-16), there are no specific obligations on those simply holding allowances. The smooth functioning of the market would be helped by permitting the widest set of potential allowance holders. We recommend that this provision be stricken and instead recommend that EPA keep such records and make them available to the public.

Page 18, line 2. FINALIZING PHASE 2 ALLOWANCES.

We strongly believe that the allowance publication date should be changed to a much earlier date. We propose that a final allocation be determined by December 31, 1991. As we stated above, we believe it is critically important to provide as much certainty as possible to facilitate energy efficient and cost efficient planning. We believe that the more time affected sources have to plan for compliance, the more sensible their compliance plans will be.

Under the draft language, sources may not know their final allowance allocation until December 31, 2000 -- the proverbial eleventh hour. This last minute notification is not necessary. Under our reading of the bill, sources can be compelled to provide to EPA an election of their baselines under section 502(a)(8) and any other election required under the Act shortly after enactment. We suggest 90 days. At that point, EPA can expeditiously propose the Phase 2 allocation and, after a reasonable comment period, this allocation can be finalized.

The only wild card in this approach is the draft's IPP provision. This provision in its current form will drain allowances from the overall pool. Although we propose some major changes to this provision below, even if the provision remains the same, the auction can be moved up from March 31, 1992, to some earlier date to force an early determination of the total amount of IPP guarantees. Once the guarantees are determined, the Administrator is free to fix the allowances.

We believe this is a noncontroversial, but immensely important change. Allowances will play a major role in compliance planning, but only if planning is permitted to take place. Under the current draft, utilities may not know the number or value of their allowances until its too late. As a result, we will lose any incentive for the greater than needed reductions on which the allowance system is based. In addition, systems operating units covered under Phase 1 or Phase 2, will be denied the flexibility to fashion the most cost-effective means to achieve pollution control among all units within their system.

Page 18, line 11. ADJUSTING ALLOWANCES UPWARD.

We oppose allowing the Administrator to adjust the cap upward, if allowances are projected to fall below 8.9 million. The Senate compromise allows EPA to make adjustments to reduce emissions, not increase them. This is a sounder, more environmentally responsive approach.

Page 18, line 21- Page 19 line 7. GAS INTERRUPTIONS RESERVE.

Although the Reserve does not bust the cap under this provision, we recommend that the Administrator be given a deadline for establishing this Reserve and that this deadline fall before the Phase 2 allocation determination that we discussed above.

Page 21, lines 7 et seq. INDEPENDENT POWER GUARANTEES.

We have several major concerns with the IPP provision. First and foremost, we are concerned that the somewhat loose qualifications for guarantees could lead to an unnecessarily large and damaging tap on the allowance pool. We believe this is unnecessary because there is a mechanism available in the Sharp Amendment to establish a separate IPP Reserve which, like the other reserves, will be fixed in size and, once depleted, will cease to exist.

Under the draft, the Renewable and Small System Reserve is established by taking the unused allowances from the DOE units accumulated during Phase 1 (i.e., the difference between .6 and 2.5 multiplied by 5). However, the last sentence on page 74 makes it clear that these units may not receive more than .6 allowances during either Phase 1 or Phase 2. That appears to leave the Phase 2 allowances for the DOE units unused. As a result, EPA will be required to distribute those unused allowances to all other Phase 2 units, as required by section 503(i).

Although there is a cross-reference to the DOE provision on page 19, line 2, as it relates to the 75,000 allowances for Gas Interruptibles, the language makes it clear that these tons are deducted from "the total of allowances that would otherwise be issued to all affected units for the Second Phase."

Unless EPA is allowed to allocate them under section 503(i), there is a potential pool of allowances for IPPs equal to the difference between .6 and 1.2 from years 2001 through the remaining useful life of the DOE units. Because these allowances can easily be directed to an IPP Reserve without any effect on the cap, we strongly recommend that such a reserve be established. Although we have other concerns with the IPP provisions, as discussed below, these concerns are much less important if the IPPs are handled in a separate reserve.

If a separate reserve is not established, we have several workability concerns with the current provision. First, there should be a cap on guarantees. We recommend a drain of no more than 100,000 allowances from the total Phase 2 allowances. This set aside, in combination with our suggestions on an early sale auction discussed below, should provide IPPs with an ample

supply of allowances.

Second, we believe the bill must establish an explicit deadline for EPA to determine the total pool of guarantees. Once again, ample planning time is the key. If the auction is moved up, the IPPs can be compelled to submit their guarantee applications almost immediately after enactment. By doing so, the IPP guarantees can be fixed and, consequently, the Phase 2 allowances can be fixed. In any event, it is critically important that any IPP guarantees be determined at the earliest possible time to allow the Administrator to adjust the allowances under section 503(i) and issue Phase 2 allowances early in the planning process.

Third, we believe that the entitlement language is not a very high hurdle to qualify for guarantees. Indeed, simply by submitting an application for financing, and circulating offers to buy allowances from Phase 1 plants (why not Phase 2 units and opt in units as well?), an IPP can qualify for a guarantee.

One way to limit frivolous applications would be to require the guarantee applicant to purchase the requested allowances, whether or not it has found allowances through other means between the time of the guarantee and the start of Phase 2. Currently, the provision requires only that the allowances "will be made available for purchase." There is no requirement to purchase, so there is no real incentive to undertake a diligent search for allowances prior to applying for the guarantee. If the guarantee is to be considered a last resort for IPPs, they should understand that they will be obligated to purchase the set aside allowances at the high bid price.

Finally, IPPs should be barred from selling or transferring guarantee allowances. It makes little sense to give the guarantee only to let the IPP later sell the allowances for a profit. Even if they are sold for a loss, the IPP may still have an incentive to seek a guarantee if it can sell the allowances at a later date for a minimal cost. Once again, in the spirit of treating these allowances as a last resort, the IPP should be forced to bear the full cost of the allowance.

Page 37, lines 11-23. BASELINES IN GROWING STATES.

This provision could bust the cap. However, it is unclear which affected units would be covered and which baseline they would select. Depending on the change in baseline, the allowances issued could exceed those authorized under H.R. 3030. What is the impact of this provision?

At a minimum, units covered by this provision should be on a deadline to select an appropriate baseline so the Administrator can determine the Phase 2 allocation.

Page 51, lines 16 et seq. OPT IN UNITS AND SUBSTITUTE UNITS.

We strongly support this section because it allows other units to come into the trading system. Their entry will bolster the market for allowances and facilitate trading.

What concerns us is not the election provision, but the substitute units authority starting on page 26, line 8. This language creates a cumbersome process to allow other units to be used to achieve the reductions required for affected units under Phase 1. If the owner chooses to achieve its reductions from units other than the listed unit, why can't the owner simply use the election provision to opt in the other units which can, in turn, sell their unused allowances to the listed unit? Using this method, both units are brought into the allowance trading system, reductions are achieved, and there is minimal delay caused by EPA review and approval. We recommend striking the substitute units provisions, as long as the baseline determinations for opt in units and substitute units are determined to be the same.

Page 70, lines 7 et seq. FEES, SUBSIDIES AND AUCTIONS.

As noted above, EDF is committed to an efficient and robust trading system in allowances. As long as allowances are sold and purchased freely, allowances will be priced according to their value in the marketplace. If the market is working properly, affected units will have an incentive to reduce emissions beyond those required by law as long as the incremental pollution control costs are less than the value of the allowance. Obviously, the lower the value of the allowance, the fewer dollars will be spent on extra pollution control.

Subsidies to affected units from fees will lower the value of allowances. As affected units rely on the benefits of the subsidy, rather than the benefits of allowances, emissions reductions will increasingly occur from a desire to obtain subsidies rather than a desire to obtain allowances. As the subsidy grows larger, affected units will no longer care about acquiring allowances, because their value relative to the subsidy has declined. As a result, the price and value of allowances can be expected to decline. Obviously, the larger the subsidy, the larger the impact on allowances.

Although we would rather not see any explicit subsidy in acid rain proposals in order to permit full use of the allowance system, we need to stress our strong opposition to any further increase in the subsidies contained in the Sharp proposal. We believe that any further increases will have a serious detrimental impact on the allowance system by diminishing the value of allowances and dampening the incentive for excess emission reductions.

We also have concerns with the auction provision. First, the auction appears to allow sales only from "owners or operators of units eligible to be fully or partially certified units." But, to be eligible, a unit must be larger than 250 Mw and must at least meet the emissions limits applicable to partially certified units. The proposal has no provision requiring units to certify or verify that they are in actual compliance with these emission

requirements. Compliance with these limits must be made explicit and a mechanism must be established to ensure compliance before the auction.

Second, there is no prohibition on the use of auction lots in years other than the year for which they were originally issued.

Third, there is no provision requiring the Administrator to maintain transaction records of sales made through the auction. We believe it is imperative to record these transactions to guarantee compliance.

Fourth, there appears to be an implicit prohibition on auctioning other allowances by eligible units. The provision only permits the sale of so-called "auction allowances," which are defined as and limited to the difference between Phase 1 allowances and baseline times 1.85 pounds. There is no reason allowances should not be auctioned for the entire amount of anticipated allowance savings (in Phase 1 and Phase 2). As long as the sale is recorded, the selling unit will simply receive fewer allowances. This change would allow more allowances to be auctioned and create more price competition in the sale price.

As an alternative or supplement to the auction provision described in the draft, we urge you to consider the auction proposal offered by Representative Oxley. His provision would actually call for two auctions. This first would be a quarterly auction of 5 percent of the allowances to be issued each year. The auction is open to all either to sell or buy allowances. The provision requires recordkeeping by the Administrator, bans the use of allowances except in the years for which they are issued, and divides the proceeds pro rata among those units from whom the allowances were withheld. No minimum price is required, but a unit is free to buy back its own allowances if it believes the auction price is too low.

In addition, the quarterly auction will provide useful pricing information to those selling and buying allowances elsewhere in the market. It will also provide a benchmark for utility regulators to gauge the value of allowances held by its regulated units.

More importantly for those electing to become fully or partially certified, the Oxley provision would provide for an early sale auction. This provision would allow any unit to sell as many allowances as they desire for as many years as they want. Under this provision, units could sell more allowances, and consequently collect more money upfront, than the Sharp auction. The Sharp auction is limited to allowances which fall between 2.5 and 1.85 pounds, and would be issued only during Phase 1. The Oxley auction would cover all allowances for either Phase 1 or Phase 2.

This is an important difference, because it provides a market for IPPs to purchase Phase 2 allowances from units planning to achieve significant reductions in Phase 1 and 2. IPPs would be able to purchase allowances for any year needed and offered. It may, in fact, lessen the need for separate IPP guarantees. A minimum price is permitted under the early sale auction to ensure that units can recover their pollution control costs, and their entry

into the auction is not mandatory.

The Oxley approach seems to achieve both major goals of the auction provision. The 5 percent auction provides a readily available pool of allowances to allay concerns that hoarding will occur. In addition, the early sale auction gives those seeking early emissions reductions a market to sell today the allowances they expect to save in the years ahead. These monies can then be used to help finance necessary pollution control measures. We urge you to consider an approach like the one contained in the Oxley amendment.

We appreciate your willingness to review our suggestions and comments, and we look forward to your response.

Honorable Philip R. Sharp
Chairman, Subcommittee on Energy
and Power
Committee on Energy and Commerce
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

Thank you for your letter of September 26, 1989 concerning the Administration's Acid Rain Bill. Our views on significant issues raised in your letter are discussed below:

(1) Higher prices for fuel switching where a utility plant is served by a single railroad. In your letter you imply that in fuel switching, railroads are likely to substantially raise their rates, especially where a utility powerplant is served by a single railroad. Hence, rail rates are likely to be much higher under acid rain regulations and were not captured in the EPA analysis.

We do not disagree that railroads could and would raise rail rates for delivering coal to captive powerplants, however, we believe these effects will be small and that in the overall regional and national markets the total costs, including rail rates for those plants shifting to lower sulfur coals, are not likely to be significantly higher than assumed in the EPA analysis.

The ability of railroads to charge higher rates will depend upon the relative competition existing not only at single powerplants but across the whole utility system. Competition will come in the form of rail to rail competition (building spurs to new lines to create competition), competition with other shipping modes (mainly barging on coastal and inland waterways), selection of alternative sources of coal (East versus West), employing lower cost

desulfurization technologies besides conventional wet scrubbing, dispatching among the different utility plants, emissions trading within the utility system and ultimately among other utility systems and other states.

There could be many powerplants now captive to a single railroad by virtue of a contracted supply of coal and established compliance strategy that could have lower rail rates due to acid rain law. These powerplants could have lower rates because of the competition between scrubbing high sulfur coals and using low sulfur coals, emissions trading or dispatching each generating unity differently to lower overall emissions.

Because scrubbing will be a cost-effective control strategy for some plants, the railroads will be facing a clear competitive threat. It may be difficult for the railroad to judge just what alternatives the utility has.

Therefore, it is important to establish an approach to acid rain control that ensures that the maximum flexibility and opportunities for creating competition or near competition in the electric utility and coal markets is achieved. We believe that the design of the Administration's bill regarding the timing of emission reduction, the emissions banking and trading provisions, and the approach to allow the markets to determine as effectively as possible where and how much each source reduces its own emissions provided accomplishes this objective.

(2) Scrubbing and fuel switching choices versus low sulfur coal prices equivalent to scrubbing costs. You asked the following question in your letter. "Also, if the utilities' choices are to scrub or to fuel-switch why wouldn't low sulfur coal suppliers raise their prices as high as the cost of scrubbers?"

Your suggestion is that because the EPA analysis assumes a competitive, active market for coal and utility compliance strategies that we understate the costs of the Acid Rain program by not capturing the ability of low-sulfur coal producers to extract higher prices and higher profits because of the new demand created for their coals.

We continue to believe that the coal markets, even for lower sulfur coals will be competitive and cost-based, and that the design of the Administration's Acid Rain bill was explicit in providing flexibility and maximum choice on the part of

individual utilities to give them the discretion to ensure cost-effective compliance strategies could be used. Therefore, we do not believe that the EPA analysis understates the costs because of this issue.

Utilities under the Administration's bill would and could pursue many more options than merely using low-sulfur coal or scrubbing. By allowing utilities to trade emissions across their system (and in Phase II across other utility systems and states), many different compliance strategies become available. Examples are -- (a) Least emissions dispatching, (b) Blending coals, (c) Shifting to medium sulfur coals at some plants and scrubbing at others, (d) New Clean Coal Technologies such as sorbent injection, (e) Coal cleaning, (f) Shifting to low sulfur oil and gas at oil/gas capable units, (g) Use of low sulfur coals from many different regions, including blending and use of coals from the Powder River Basin.

The coal markets in the U.S. are national markets with ready access to many different coal supply regions and different utility markets. Therefore, the ability for a large number of suppliers to extract very high profits and "gouge" utilities pricing their coals at each plant to the cost of scrubbing at that plant will not happen. There will be an increase in low sulfur coal prices due to the higher demands. There will also be a decline in the forecast prices for high sulfur coals due to the drop in demand for these coals. Both price changes have been incorporated into the EPA analysis. For those plants where the relative prices of these coals make scrubbing more attractive, we forecast scrubbers to be used, where low sulfur coal is still cheaper on a delivered basis, then we forecast fuel shifting will be employed. For those plants where the costs between different compliance strategies are close, there could be differences in what utilities choose to do and what our analysis shows. But in these cases, while compliance choices would change the costs would not, since either of the strategies cost about the same.

Finally, some of the assumptions in the EPA analysis are conservative and could result in lower costs than we have predicted. Examples are -- (a) Use of low sulfur coals from the Powder River Basin were not included as a compliance strategy. However, blending of these coals with medium sulfur coals to meet existing regulations more cheaply is being done now. (b) More extensive use of coal cleaning in combination with other moderate control strategies was not assessed in much detail. More coal cleaning is likely and could reduce

costs. (c) New Clean Coal Technologies such as sorbent injection could be significantly cheaper than conventional scrubbing technologies but were not assumed to become available at any time in the EPA analysis.

Therefore, in the broad sense, we do not believe that the EPA analysis underestimates the cost impacts of the Administrations' Acid Rain bill.

(3) EPA versus Indiana cost estimates. In your letter you pointed out that EPA cost estimates for Phase I of the Administration's Acid Rain bill range from \$23 - \$60 million per year compared to \$182 million per year for an Indiana State Government estimate (Three to six times higher than the EPA estimate). Thus you believe that the EPA study results in an underestimate of costs.

We have reviewed the Indiana study and believe that it significantly overstates the electric utility costs for the Administration's Acid Rain bill. Therefore, we stand by the costs outlined in the EPA analysis. Discrepancies between the EPA and Indiana State Government cost estimates in several areas are as follows:

(a) Consistency in basis for dollar cost estimates -- The Indiana study states the results in 1988 dollars or "constant dollars," similar to the EPA study (which also reports results in 1988 dollars). In other words, both of these studies presumably report cost estimates in today's dollars, excluding future inflation. However, in calculating the capital costs, the Indiana study uses a fixed charge rate which erroneously includes inflation or calculates costs in future dollars. The result of this financial error is to overstate capital costs in the Indiana study by approximately 50 to 75 percent.

(b) Program Implementation -- The Indiana study appears not to have included any inter-utility trading within Indiana in Phase I or interstate trading with other states in Phase II. This would overstate compliance costs. If Indiana chose not to trade at all, for whatever reason, the incremental cost so incurred would be voluntary, and should not be counted in a national analysis.

(c) Low sulfur coal prices -- The Indiana study assumes that low sulfur coal prices will increase in response to greater demand for these coals but appears to ignore high sulfur coal price decline despite significantly lower demand for these coals. The EPA cost estimates do account for such a likely decline. Since about 20 percent of Indiana's coal capacity is already scrubbed or unaffected by the bill's provisions, these plants can continue to burn higher sulfur coals but at lower cost. This factor was not incorporated in the Indiana Phase I or Phase II cost analysis.

In Phase I, the Administration bill allows for the use of medium sulfur coals as well as low sulfur coals, some of which can be obtained locally -- in many cases at relatively modest price premiums. In contrast, the Indiana study assumes only one low sulfur coal option from Central Appalachia is available, that being shifts to a "compliance" coal of about 0.7 % sulfur. In fact, a number of other options are available to these plants from Central Appalachia, including the use of 1 % sulfur or 1.5 % sulfur coal in Phase I and Phase II. Since there is a substantial amount of excess capacity of these low sulfur coals at existing mines, these options represent a particularly important and low cost option in both Phase I and Phase II -- which is neglected in the Indiana study.

In Phase II, EPA estimates that prices of low sulfur coals at the mine would increase by about \$3 to \$4 per ton (in real 1989 dollars) above levels in the base case to \$32 to \$33 per ton (in real 1989 dollars), or about a 10 to 15 % increase in prices. This represents in real dollars about a 30 to 40 % increase in low sulfur coal prices from today's levels of about \$24 per ton at the mine. Note that in real terms since 1975 low sulfur coal prices have fallen by more than 50 %.

In contrast, the Indiana study assumes F.O.B. mine prices of \$40 per ton (in 1988 dollars) for low sulfur Central Appalachia compliance coal. This price is far higher than recent forecasts of these prices from utility planners and independent forecasting companies. Most importantly, such prices are totally inconsistent with market economics. They could not be supported for any long-term period in the market place since they would lead to mostly scrubbing and little increase in demand for Central Appalachia compliance coal which, in turn, would

result in little increase in prices. A market equilibrium price of closer to \$32 to \$33 pr ton would result in some retrofit scrubbing but also a significant amount of fuel switching to Central Appalachia coals.

(d) Technology costs -- About one-fifth of the reductions in Indiana are expected to be achieved through scrubbing in Phase II. EPA scrubber costs estimates indicate that these reductions would cost about \$200 to \$400 per ton removed, or an average of about \$300 per ton removed in line with the average costs of all SO₂ reductions forecasted for Indiana. The EPA estimates are based on EPRI/Stearns Rogers cost assumptions, as interpreted by RCG/Hagler, Bailly, Inc. with plant-specific retrofit factors added to account for the degree of difficulty in retrofitting a scrubber. Note that these estimates are similar to many recent industry estimates and specific utility company estimates in other states and, correcting for the overstatement of capital charges noted earlier, are similar to the Indiana State Government estimates.

(e) Conservative cost estimates in EPA study -- The EPA study was in many respects conservatively high with respect to its forecasted costs of acid rain control costs.

In particular, it did not assume the availability or use of low sulfur subbituminous coals in boilers currently designed for bituminous coals. Many plants in Wisconsin, Illinois, and Missouri have already converted to greater use of these coals because of lower costs. Northern Indiana Public Service is currently testing these coals at several bituminous boilers. Sub-bituminous coals are abundant and are expected to remain very inexpensive.

The availability of clean coal technologies was not assumed in Phase I or Phase II. These technologies have considerable promise and could lower compliance costs significantly.

The study did not assess or include emissions banking or NO_x or SO₂ trading allowed under the bill. The exercise of these options could lower costs as well.

(4) Loss of high sulfur coal mining jobs. In your letter you express concern over the loss of 17,000 high sulfur coal mining jobs.

We appreciate and share these concerns. However, we would also point out that these are job slots and not jobs and with attrition that can occur through advance notice by passage of the legislation several years before it is implemented, the actual jobs impacts may be considerable less. These impacts may be mitigated further in some high sulfur coal states, where the Governor has the authority (by state law) to require the use of in-state coal. Even if the bill does not become law until late 1990, sources would have over five years to comply with Phase I requirements where scrubbers, FBC, and sorbent injection could be used to reduce sulfur emissions without impacting high sulfur coal jobs.

However, we do acknowledge that any acid rain bill is likely to impact high sulfur coal mining jobs, at least in the near term, if it is to be cost effective. On the other hand, we recognize that high sulfur coal, that is burned cleanly, is important to our nation's social, economic, environmental, and energy future and we believe that the flexibility, market incentives, and clean coal technology incentives that are contained in the Administration's bill will result in the continued utilization of these high sulfur coal resources during the next century.

(4) Burden - sharing. In your letter you state the following: "Your choice of Midwest and Southeast coal-fired powerplants as the optimal compliance targets bestows a benefit upon all those states that are thereby relieved from having to pay for reductions. Your rejection of burden - sharing means that the Midwest and Southeast must pay for that benefit."

Your statements are correct and we believe our choice is fair and just. First of all, we agree that the Administration's bill leads to an efficient solution to the acid rain problem (i.e. a "least cost" solution for the nation). Furthermore, it is obvious that when the Midwest and Southeast pays for its emission reductions (absent burden - sharing from the other states) that the other states are relieved from these costs. However, we believe that this approach is fair and just because the electricity produced in the Midwest and Southeast bears the cost of the resulting pollution controls and the states who have already cleaned up their pollution do not have to pay a second time.

We hope that the responses to your questions contained in this letter along with our recent testimony and answers to other questions that you and other members of your Subcommittee have raised have helped to clarify our views on this important subject. However, if you have additional questions, please let me know and we will respond to them as soon as possible.

Sincerely yours,

William K. Reilly

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Arguments in Support of Acid Rain
"Cost Shaving"**ROUTE TO:****ACTION****DISPOSITION**

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ANALYSIS OF PUBLIC SERVICE INDIANA'S (PSI) ARGUMENTS
IN SUPPORT OF ACID RAIN "COST SHARING"

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Attachments

*ADDENDUM: Shows reduction in PSI electric bills during 1988 and compares
monthly bills for high and low SO2 emitting utilities on
January 1, 1988 and January 1, 1989.

ANALYSIS OF PUBLIC SERVICE INDIANA'S (PSI) ARGUMENTS
IN SUPPORT OF ACID RAIN "COST SHARING"

A. EXECUTIVE SUMMARY:

1. PSI Arguments. Officials of Public Service Indiana (PSI) and some Members of the Congress from Indiana have argued strenuously that costs of complying with proposed acid rain legislation should be spread to others -- so as to reduce the adverse impact on electric utilities, such as PSI, that face high costs of reducing their SO2 emissions. PSI officials have indicated that PSI faces costs ranging from \$600 million to \$1.2 billion to comply with pending legislation (Attachment A).
2. "Cost Sharing." Despite provisions in H.R. 3030 to give valuable allowances to utilities with high emissions (See Section F, page 7), several proposals for a new Federal tax and for subsidies for high SO2 emitting utilities -- called "cost sharing" -- have been proposed. These proposals to provide subsidies would be financed with either a new Federal tax on electricity generation and imports, or on SO2 emissions from utilities and industrial facilities.
3. Analysis. The various "cost sharing" proposals would shift significant costs from high SO2 emitting utilities to customers of electric utilities that already have lower SO2 emissions. This analysis addresses the fairness of the proposed shift in cost, focusing on two important considerations:
 - a. Fossil fuel costs (coal, oil & gas) paid by PSI. PSI's costs for the 1984-88 period are compared with costs incurred by other utilities. This analysis identifies the amounts saved for customers by PSI by using low cost high sulfur coal rather than lower sulfur fuels used by utilities that have already reduced SO2 emissions.
 - b. Monthly electric bills for PSI. PSI customers' monthly electric bills are compared to bills for customers of utilities that have already reduced SO2 emissions (and whose customers are already paying the costs).
4. Conclusions. The results of the analysis, all of which are based on publicly available data reported by utilities, show that a tax (whether on electric generation or SO2 emissions) paid by electric customers would be grossly unfair to millions of people, particularly residential customers of utilities that have already acted to reduce SO2 emissions. Some specific examples appear immediately below. Details are provided beginning in Section B.

In summary, this analysis shows that Public Service of Indiana:

- . Has saved substantial amounts of money for its customers by using low cost, high sulfur coal -- rather than lower sulfur fuels. The amounts saved in just the 5-year period from 1984-1988 exceed PSI's estimated cost of compliance with pending acid rain legislation.

- . Has residential electric bills comparable to the national average and well below the bills paid by millions of customers served by utilities that have already reduced SO2 emissions.

More specifically:

- a. Fossil fuel costs. Customers of PSI have saved the following amounts in fossil fuel costs during the 1984-88 period compared to fossil fuel costs paid by customers of other utilities shown:

- . \$2.0 billion compared to Commonwealth Edison of Illinois which uses low sulfur coal to reduce SO2 emissions.
- . \$1.8 billion compared to utilities in New York state which use lower sulfur coal, oil and natural gas to reduce SO2.
- . \$2.9 billion compared to utilities in California which switched to very low sulfur oil and natural gas to reduce SO2 emissions.

Other examples are provided in Section D.4, below.

- b. Typical monthly electric bills. A typical monthly electric bill as of January 1, 1988, for a 500 kilowatt-hour per month PSI residential customer was \$47.11.

According to PSI officials, PSI rates were reduced 9% during 1988 and 4% in October 1989 (See Attachments A and B). Apparently PSI rates were higher than for other utilities using similar low cost, high sulfur coal because of upward adjustments in PSI rates in the early or mid-1980's associated with the failed Marble Hill nuclear power plant and related financial difficulties.

For comparison with PSI's \$47.11 rate for January 1, 1988 (before 1988 and 1989 reductions):

- . Long Island Lighting bills of \$60.81 for a similar customer were 29.1% above PSI.
- . Consolidated Edison bills of \$62.35 for a similar customer in New York City were 32.3% above PSI.
- . Commonwealth Edison bills of \$43.09 for a similar customer in Illinois communities were slightly below PSI but have since been raised.
- . The national average bill of \$41.21 for a similar customer was also below the PSI rate, but the national average has almost certainly increased since January 1, 1988, while PSI's rates have decreased (Attachments A & B).

Other comparisons are shown in Section E, below.

An increase in PSI rates "as much as" the 24% claimed by PSI officials would leave bills for a 500 kilowatt-hour per month customer well below bills for a similar customer of Long Island Lighting, Consolidated Edison of New York and various other utilities -- particularly when taking into account the decreases reported by PSI.

Further, electric bills for low SO2 emitting electric utilities using low sulfur fossil fuels will increase when acid rain legislation takes effect because the price of low sulfur fuel will rise as utilities now having high SO2 emissions begin competing for it.

B. PSI EMISSION LEVELS.

According to data from the National Coal Association (NCA), PSI emitted some 475,000 tons of SO2 from 6 coal-fired power plants in 1987. The largest power plant emitted over 270,000 tons and had an SO2 emission rate of 3.66 lbs. of SO2 per million BTUs of energy, a high rate. A second plant emitted 110,000 tons and had an emission rate of 4.27 lbs. of SO2 per million BTUs.

C. ANALYSIS OF FOSSIL FUEL COSTS.

As one way of assessing the fairness of asking electric customers nationwide to help pay clean up costs for high SO2 emitting utilities, this analysis identifies how PSI's customers fared compared to customers of certain utilities that have already reduced SO2.

Specifically, this analysis compares fossil fuel costs incurred by PSI to those incurred by other utilities using primarily low sulfur fuels rather than high sulfur coal. Comparisons are made with the average fossil fuel costs incurred during the 1984-1988 period by:

- . Commonwealth Edison Company of Illinois,
- . All utilities in the U.S.,
- . All utilities in 4 states and in regions that have already made major strides in reducing SO2 emissions: New York, California, Texas, Florida, and the New England region.

Commonwealth Edison's fossil fuels were primarily low sulfur coal. New York utilities' fossil fuels were about 20-25% coal and the rest oil and natural gas. California utilities' fossil fuels were primarily natural gas. Texas utilities' fossil fuels were about half low sulfur coal and half natural gas. Florida utilities' fossil fuels were 50-60% coal and the rest oil and natural gas. New England utilities' fossil fuels were about 25-30% coal and the rest oil and natural gas.

Generally, low sulfur fuels cost more than high sulfur fuels.

This analysis compares average \$ per million BTUs and then calculates amounts saved by PSI for its customers during the 5-year period by using low cost, high sulfur coal rather than low sulfur fuel.

D. HOW MUCH LESS DID PUBLIC SERVICE INDIANA PAY CUSTOMERS FOR FOSSIL FUELS DURING THE PERIOD FROM 1984-1988 THAN IT WOULD HAVE PAID IF LOWER SULFUR FUEL WAS USED?

The answer to this question is derived in four steps:

1. How much fossil fuel (coal, oil and natural gas) did PSI buy during the 1984-1988 period and what did it cost?

This table shows amounts of fossil fuel bought in each of the five years, the average delivered cost per million BTUs, and the total annual and five-year costs:

<u>Year</u>	<u>Quantity (Billion BTUs)</u>	<u>Average \$ per Million BTUs</u>	<u>Total Fossil Fuel Cost</u>
1984	330,213	\$1.383	\$456,684,579
1985	268,166	\$1.440	386,159,040
1986	239,881	\$1.482	355,503,642
1987	246,976	\$1.535	379,108,160
1988	235,822	\$1.518	<u>357,977,796</u>
			\$1,935,433,217

2. What were the average fossil fuel costs -- in \$ per million BTUs -- paid by others who had lower SO2 emissions?

This table identifies the average fossil fuel costs -- in \$ per million BTUs of energy -- in each year for Commonwealth Edison and for all utilities in four states (New York, California, Texas and Florida), all utilities in New England, and all U.S. utilities combined.

<u>Year</u>	<u>All Electric Utilities:</u>						<u>Total U.S.</u>
	<u>Commonwealth Edison (Ill)</u>	<u>New York</u>	<u>Cali- fornia</u>	<u>Texas</u>	<u>Florida</u>	<u>New England</u>	
1984	\$3.030	\$3.732	\$5.128	\$2.504	\$3.099	\$3.952	\$2.191
1985	3.190	3.268	4.497	2.438	2.697	3.329	2.096
1986	3.052	2.211	2.845	1.923	2.030	2.191	1.749
1987	2.968	2.464	2.511	1.804	2.224	2.458	1.707
1988	2.680	2.197	2.805	1.763	1.932	2.112	1.643

3. How much would PSI have paid for fossil fuels if it had paid as much as was paid by others who used lower sulfur fuels?

The following table shows what PSI would have paid each year if it had purchased fuels at the prices paid by other utilities in the comparison groups -- instead of the lower prices PSI paid for low cost, high sulfur coal:

What PSI would have paid if it used lower sulfur fuels at prices paid by other utilities in comparisons (\$ in millions)

Year	PSI's BTUs(in Billions)	Common- wealth Edison	New York	Cali- fornia	Texas	Flor- ida	New Eng- land	Total U.S.
1984	330,213	\$1,001	\$1,232	\$1,693	\$ 827	\$1,023	\$1,305	\$ 723
1985	268,166	855	876	1,206	654	723	893	562
1986	239,881	732	530	682	461	487	526	420
1987	246,976	733	609	620	446	549	607	422
1988	235,822	632	518	661	416	456	498	387
Total		3,953	3,766	4,863	2,803	3,238	3,828	2,514

4. During the 5-year period, how much did PSI customers save by using low cost high sulfur coal -- compared to others shown above?

This table summarizes the savings enjoyed by PSI customers during the period from 1984-1988 because of the use of low cost, high sulfur coal rather than higher cost, low sulfur fuels. The numbers are calculated by subtracting PSI's actual costs shown in the table in paragraph 1, above from those shown in Paragraph 3, above.

Five-year savings -- in millions of \$ -- compared to:

All Utilities in						
Commonwealth Edison (Ill)	New York	Cali- fornia	Texas	Florida	New England	Total U.S.
\$2,018	\$1,830	\$2,928	\$ 868	\$1,303	\$1,893	\$ 579

E. COMPARISON OF TYPICAL MONTHLY ELECTRIC BILLS FOR 500 KILOWATT-HOUR PER MONTH RESIDENTIAL CUSTOMERS - RATES IN EFFECT ON JANUARY 1, 1988

The U.S. Department of Energy (Energy Information Administration) annually collects from electric utilities and publishes information on typical electric bills for residential customers as of January 1.

Since PSI officials expressed concern about the impact of compliance with acid rain legislation on electric rates, it is important to compare recent rates for PSI with those of other utilities, particularly those in regions that have already reduced emissions.

1. Comparison of PSI's and national average bills -- January 1, 1980 thru January 1, 1988; and subsequent PSI rate decreases.

Electric rates are affected by a variety of factors. One important factor is the cost of fuel and other actions necessary to meet environmental requirements. While Public Service Company of Indiana's bills have been held down by using low cost, high sulfur coal, PSI's rates apparently were pushed up significantly by costs or other factors approved by the Indiana Utility Regulatory Commission associated with the failed Marble Hill nuclear power plant (See Attachments A & B).

Thus, despite use of low cost, high sulfur coal, PSI rates increased rapidly during 1981, 1983 and 1985 -- before turning downward in 1987 (See Attachments A & B). The following table compares PSI and national average rates for a 500 kilowatt-hour per month customer for the years 1980 through 1988:

This section of the analysis compares typical monthly bills for 500 kilowatt-hour per month residential customers.

<u>In Effect on Jan. 1</u>	<u>National Average</u>	<u>PSI</u>
1980	\$27.80	\$27.31
1981	\$32.61	\$28.72
1982	\$36.96	\$35.39
1983	\$38.35	\$36.58
1984	\$40.18	\$41.40
1985	\$41.86	\$42.46
1986	\$42.54	\$44.21
1987	\$40.88	\$48.09
1988	\$41.21	\$47.11

Also, according to PSI (Attachments A & B), rates were reduced by 9% in 1988 and 4% in 1989. Information is not yet available from DOE on the resulting bills for a 500 KWH residential customer. If the PSI \$47.11 per month bill were reduced by a full 13%, PSI's bill for a typical 500 KWH residential customer as of January 1, 1990 would be about \$41.00 per month.

2. Comparison of PSI's January 1, 1988 bills with those of other utilities.

The following analysis compares PSI rates as of January 1, 1988 (as reported to the U.S. DOE) with rates for certain other utilities, states or regions:

	<u>Typical Monthly Bill (500 KWH) as of 1/1/88</u>
a. <u>Bill for Public Service Company of Indiana (PSI)</u>	\$47.11
b. <u>Example bills for several utilities that have reduced SO2 emissions by using lower sulfur fuel (oil, coal or natural gas)</u>	
. Consolidated Edison (New York City)	\$62.35
. Long Island Lighting Company	\$60.81
. San Diego Gas & Electric	\$57.36
. Orange & Rockland (New York)	\$58.87
. Commonwealth Edison (Illinois)	\$43.09

c. Average bills in certain states that have already significantly reduced SO2 emissions

. New York	\$54.53
. Connecticut	\$49.40
. Massachusetts	\$44.67
. Arkansas	\$44.39
. Arizona	\$43.70
. California	\$43.12
. New Mexico	\$42.24

d. National average bill \$41.21

- F. Economic Advantage for high SO2 emitters in President's bill. The acid rain portion of the Bush Administration's proposed Clean Air Act amendments include significant economic advantages for many high SO2 emitting utilities in that utilities would be awarded SO2 emission "allowances" which could be sold or traded. Such allowances are expected to have significant value. They would have high value because some existing emitters face very high emission reduction costs and will likely seek to buy "allowances." Also, owners of proposed new SO2 emitting facilities would have to obtain "allowances" to cover their emissions and would be forced to buy "allowances."

Thus, high SO2 emitting utilities that can reduce SO2 emissions at relatively low cost per ton of SO2 reduced would have an opportunity to sell their "allowances" at a price above their cost of reducing SO2. This would reduce their net cost of meeting acid rain requirements -- with a resulting shift in costs to the customers of the company buying the allowances.

G. SOURCES OF DATA

1. Fossil Fuel Costs and Quantities. Data on fossil fuel costs and quantities used in this analysis were found in:
 - . Costs and Quality of Fuels for Electric Utilities (DOE/EIA-0101), Tables 38 and 52, U.S. Department of Energy, Energy Information Administration.
 - . Electric Power Quarterly (DOE/EIA-0397(40)), Tables 5, 9 and 12, U.S. Department of Energy, Energy Information Administration.
 - . Steam Electric Plant Factors, 1984, National Coal Association, Table 1.
2. Typical Electric Bills. Information obtained from Typical Electric Bills for years listed below (Tables 9 & 21), U.S. Department of Energy, Energy Information Administration, based on data reported by utilities on Form EIA 213. Document numbers are DOE/EIA-0040(80 - 88).

3. S02 Emissions. Data on S02 emissions were obtained from the National Coal Association's (NCA) annual analysis of S02 emissions from coal-fired power plants of 50 megawatts or more, released in mid-1988 and covering emissions through 1987. (NCA has not yet released its analysis of 1988 S02 emissions which apparently increased over 1987 levels.)

Taking the initiative for cleaner air

By JAMES E. ROGERS JR.

For years utility companies, environmentalists and other interested parties have argued over the merits of acid rain legislation. In the past much of the debate has centered on the science of what is a very complicated issue. Today, however, with the changed political climate in Washington, the question is less, "Is there a problem?" than "How can we address the issue at an acceptable cost?"

William Reilly, who now heads the Environmental Protection Agency, says the first item on his agenda will be legislation to strengthen the Clean Air Act. A major component of that legislation, he says, will be a program for reducing acid rain.

Richard Trumka, president of the United Mine Workers, has also publicly endorsed an acid rain bill, so long as it protects Midwest and Appalachian coal miners.

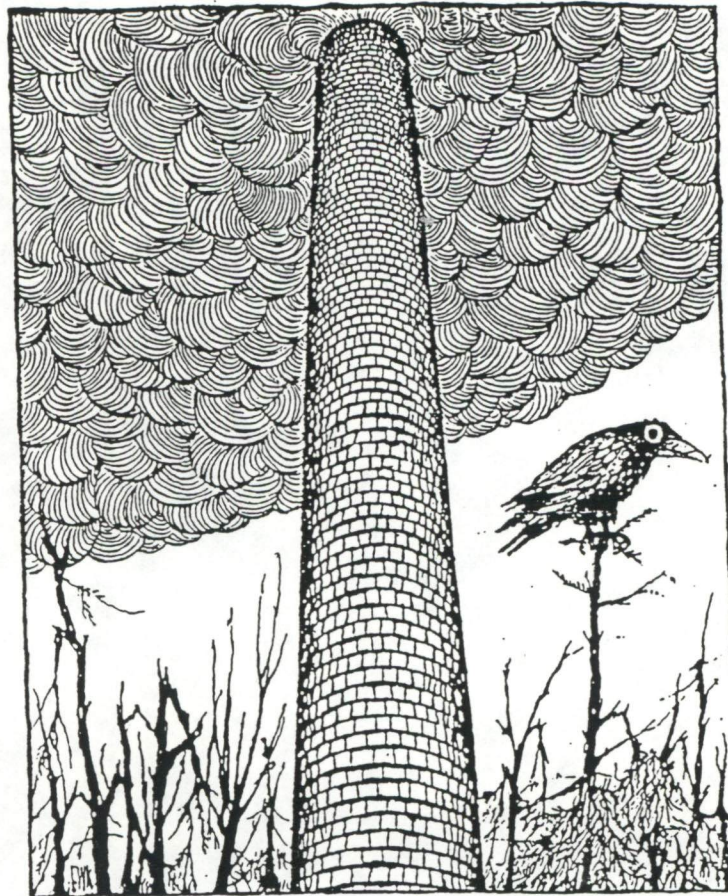
Sen. Richard Lugar, R-Ind., has been closely following the acid rain issue for years. He favors reductions, correctly noting that "the vast majority of people in Indiana want a solution to the acid rain problem."

Anyone who follows the news can see that acid rain legislation is much more likely to be passed with the election of a new president, changes in Congress and greater public concern. More than 100 members of the House have sponsored a bill to reduce sulfur dioxide emissions by more than 40 percent. Both the Senate and the Bush administration also are expected to submit bills by the end of May. My discussions with lawmakers and their staffs indicate that acid rain legislation is likely to pass in the 101st Congress.

ONE WAY to deal with this reality is to fight it. Pollution cannot be reduced without increasing costs. Utilities and their customers alike will pay a price. Nonetheless, I believe the time is right for leadership on this issue.

In the coming months our company, Public Service Indiana, will be working closely with the Indiana congressional delegation and other Hoosiers to formulate a solution. I already have met with Rep. Phil Sharp, D-Ind., who is a member of the House Energy and Commerce Committee. I believe a plan can be worked out which is good for both Indiana and the nation.

Creating a solution won't be easy. For the past six years Con-



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gress has hotly debated but failed to act on initiatives to reduce sulfur dioxide emissions. Intense regional conflicts are the crux of the problem. Northeastern states want quick action to prevent damage to their lakes and forests. Midwestern and Southeastern states depend on high sulfur coal as a source of both employment and energy. Western states have large deposits of "cleaner" low sulfur coal they use themselves and market to others.

Until now, Congress' inability to reconcile these regional interests has stymied efforts to legislate further controls. With a much greater likelihood that action of some type will be taken, however, it is essential that we have a say in the end result.

WE INTEND to emphasize two important principles: flexibility and fairness. Local regulators and utilities must be given flexibility in choosing the means of compliance. The cost of compliance also must be fairly distributed.

In some regions, burning low sulfur coal will be the least costly, most acceptable way to reduce sulfur emissions. In Indiana, mechanical devices called

"scrubbers" may be the better solution. Public Service Indiana currently is the largest purchaser of Indiana coal. We would like to continue doing business with suppliers who are our customers as well. Clean air is important, but so are the jobs of Indiana miners. Rather than prescribing methods of compliance, Congress should provide states and utilities the flexibility to adopt methods which are regionally appropriate.

Just as important as flexibility in compliance is fairness in funding. The environmental benefits of cleaner air will accrue to the nation as a whole. By contrast, the communities whose jobs, industries and economic well-being depend on coal-generated energy are located primarily in the Midwest.

Up to 89 percent of Public Service Indiana's generating capacity may require new pollution controls, for example. The cost could range from \$600 million to \$1.2 billion for PSI alone. Rate increases totaling as much as 24 percent could be required by the late 1990s.

Fairness requires that no single region be burdened with the bulk of the expense. Clean air is a national goal and the nation

should help bear the cost of attainment.

The United States has a long history of funding regional energy projects on a nationwide basis. Hydroelectric dams in the Tennessee Valley and in the Pacific Northwest are just one example of the cost-sharing tradition under which Indiana citizens have subsidized others. The case for national funding of acid rain controls is even stronger, since the benefits are national.

EVEN IF Congress allows equitable cost sharing and flexible means of compliance, the dates of compliance are also a serious concern. We recognize that action cannot be put off forever, but compliance dates which are too early can add millions of dollars to the cost. If a reasonable period is not allowed, PSI and other companies may have to pay premium prices to expedite construction. There is a question whether the nation's scrubber manufacturers and installers could even keep up with the demand.

If acid rain legislation is going to be passed, the fact that PSI's rates have been going down will ease the burden. Our rates were reduced 9 percent in 1988 and they are going down another 4.2 percent in October 1989. Public Service Indiana also plans to offer innovative new ways for customers to hold down their costs through load management and conservation.

In order to comply with any new environmental legislation, PSI will require a significant amount of outside funding. If we are to obtain this funding at the lowest cost, the investment community will require us to be a financially healthy utility. That means our rates must remain stable after this year's rate decrease. It also means we must increase the dividend which was only recently reinstituted. The better our financial health when acid rain controls are required, the lower the cost to finance them.

Our goal is to protect Indiana's economy, its industries, coal miners and electric customers. If we wait or do nothing, a solution will be forced on us. Only if we take the initiative will Indiana and the nation both win.

Rogers is chairman and chief executive officer of Public Service Indiana and its parent, PSI Holdings.

Excerpts from the 1988 Annual
Report of PSI Holdings, Inc. and
Subsidiary, Public Service Indiana

regulatory asset of \$475 million. Such amount was equivalent to future income tax benefits arising from the Marble Hill loss which PSI projected it would realize during 1986-1989. The regulatory asset will be reduced as the tax benefits are realized. If Federal or state income tax rates decrease during the period, no adjustment for that reason will be made to PSI's retail rates; however, a further reduction of the regulatory asset by a charge to operating expense will be recorded in each applicable year. Such charge will be equal to the difference between the tax benefits realized at the lower tax rate and what the tax benefits would have been if computed at the combined statutory tax rate of 48.16%. Any portion of the regulatory asset remaining on January 1, 1990, will be recovered through rates over a 5-year period, commencing on January 1, 1990. In that event, income tax expense charged in rates after January 1, 1990, will be credited for income tax reductions realized by the actual utilization of any unused portion of the net operating loss carryforward related to the regulatory asset remaining on January 1, 1990.

Intervenors Citizens Action Coalition, City of Terre Haute and Save the Valley have appealed to the Indiana Court of Appeals (Court of Appeals) requesting nullification of the March 1986 Order. Issues being raised on appeal relate to rate of return, income tax expense and recognition of the regulatory asset, rate treatment of the 5% emergency increase previously collected, lack of prudence findings on Marble Hill and certain due process questions concerning the rate proceedings. PSI believes that the March 1986 Order should be upheld.

In June 1987, the Indiana Commission issued an order (June 1987 Order) concerning the implementation of the reduction in the Federal income tax rate for Indiana utilities. The Indiana Commission confirmed the determination contained in its March 1986 Order that PSI's retail rates should not be reduced during the 1986-1989 period by reason of such reduction in the Federal income tax rate. Essentially the same parties to the appeal of the Indiana Commission's March 1986 Order have appealed the June 1987 Order as it relates to PSI. PSI believes that the June 1987 Order should be upheld on appeal.

In October 1987, Citizens Action Coalition, City of Terre Haute, Save the Valley and certain other retail ratepayers filed a complaint with the Indiana Commission seeking a reduction in PSI's retail rates and the establishment of permanent rates (Complaint Proceeding). The complaint requested a reduction in revenue of \$260 million related to rate of return, income tax expense, reduction of the regulatory asset and alleged excess generating capacity. PSI filed with the Indiana Commission a motion seeking dismissal of the complaint or denial of the requested rate reduction.

In February 1988, the Indiana Commission terminated the Complaint Proceeding and ordered its staff to conduct an investigation into the reasonableness of PSI's retail rates. Hearings were held in April 1988 to consider the extent to which the conditions creating PSI's financial emergency had changed. Additionally, the Indiana Commission considered whether certain modifications to the March 1986 Order were necessary prior to consideration of the staff's investigation of PSI's rates.

In June 1988, the Indiana Commission issued an order (June 1988 Order) approving an \$80 million (9%) annual reduction in retail

4. Rates. In March 1984, the Indiana Commission approved an annual interim emergency rate increase of 5% based on a Settlement Agreement (1984 Agreement) between PSI, the Office of Utility Consumer Counselor (Utility Consumer Counselor) and certain intervenors. Amounts collected from this rate increase (\$68 million through December 1985) were deferred, and not reflected in revenues, pending resolution of the Marble Hill issue.

In January 1986, PSI entered into a Settlement Agreement (1986 Agreement) with the Utility Consumer Counselor for the purpose of resolving issues related to Marble Hill and establishing a basis for the financial recovery of PSI. The 1986 Agreement was submitted to the Indiana Commission for approval. In March 1986, the Indiana Commission issued an order (March 1986 Order) approving the \$68.2 million (8.2%) annual rate increase included in the 1986 Agreement. Under the provisions of this order,

- PSI will not seek recovery of Marble Hill costs in retail rates.
- The 5% emergency increase was continued and incorporated into base rates. Amounts collected prior to 1986 (\$68 million), were reflected in 1985 operating revenues.
- In order to avoid the negative common equity that would have resulted from the write-off of Marble Hill, PSI was allowed for regulatory and accounting purposes to record and recognize a

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

rates effective July 1, 1988, a one-time cash payment of \$50 million to retail ratepayers on September 1, 1988 and a further \$37 million (4.2%) annual reduction in retail rates effective October 1, 1989. In approving these rate actions, the Indiana Commission acknowledged that PSI's financial emergency continued; however, its financial condition had improved to the extent that a phase-out of emergency rates and a one-time cash payment to ratepayers were possible. Other major provisions of the June 1988 Order are as follows:

- The rate reductions and cash payment will first be applied as an accelerated reversal of \$72 million of deferred income taxes.
- In future ratemaking proceedings, PSI's retail rates will reflect the effect of the accelerated reversal of deferred income taxes.
- All other provisions of the March 1986 Order including the assurances related to recording of the regulatory asset remain in full effect.
- PSI will file for permanent rates on or before April 1, 1989.
- The Indiana Commission staff's investigation into the reasonableness of PSI's retail rates was terminated.

Through June 1989 the after-tax effect of the 9% reduction and the \$50 million cash payment will be offset by the accelerated reversal of deferred income taxes, thereby eliminating the effect on operating income during such period.

Citizens Action Coalition, City of Terre Haute and Save the Valley have initiated an appeal of the June 1988 Order. They also filed a complaint seeking a court order compelling the Indiana Commission to hold further hearings on PSI's retail rates. In October 1988, the Parke Circuit Court ordered the Indiana Commission to conduct further proceedings in the rate investigation which had been terminated as a result of its June 1988 Order. Also in October 1988, Citizens Action Coalition, Save the Valley and City of Terre Haute filed with the Indiana Commission a motion to reopen the rate investigation and to establish a schedule for the pre-filing and hearing of evidence. In November 1988, the Court of Appeals granted the Indiana Commission's request to stay further proceedings pending an appeal of the Parke Circuit Court's judgment. The Indiana Commission has initiated such an appeal. PSI cannot predict the outcome of the appeal, or what effect, if any, such further proceedings, if conducted, would have on PSI's retail rates.

Through December 31, 1988, retail revenues collected in excess of those based on rate levels existing prior to the initial emergency rate increase in March 1984 were approximately \$265 million. Such amount is net of approximately \$100 million of revenue reductions resulting from the June 1988 Order, which were applied as an accelerated reversal of deferred income taxes. If the Indiana Commission's March 1986 Order were to be ultimately nullified, PSI could be required to refund the increased revenues authorized by such order, plus interest.

ADDENDUM TO
ANALYSIS OF PUBLIC SERVICE INDIANA'S (PSI) ARGUMENTS
IN SUPPORT OF ACID RAIN "COST SHARING"

The February 6, 1990 Analysis of PSI arguments (on page 6) pointed out that PSI officials expected electric rates to decline by 9% in 1988 and 4% in 1989, but that information was not available from DOE publications to show the precise impact on a 500 kilowatt-hour per month residential customer's bill.

Since the Analysis was prepared, information on January 1, 1989 bills has become available from the National Association of Regulatory Utility Commissioners (NARUC).

The table below shows typical monthly bills for a 500 kilowatt-hour per month customer as of January 1, 1988 and January 1, 1989 for Public Service Indiana (PSI) and for several other companies. In brief, these data show:

- . PSI bills declined sharply during 1988 -- from \$47.11 to \$43.52 or 8.2%.
- . Bills for other high SO2 emitting utilities have stayed about level.
- . Bills for high SO2 emitting utilities are well below the utilities listed below that have already acted to reduce SO2 emissions.
- . Monthly bills for the utilities that have already reduced emissions rose -- some sharply -- from January 1, 1988 to January 1, 1989.

In short, customers of the high SO2 emitting utilities are continuing to get a substantial price break compared to the utilities that have already cleaned up.

	Typical Monthly Bills - 500 KWH Per Month Residential Customers	
	<u>1/1/88*</u>	<u>1/1/89**</u>
<u>Bill for Public Service Indiana</u>	\$47.11	\$43.52
<u>Example bills for High SO2 emitting utilities in other states</u>		
. Illinois Power Company	\$34.73	\$34.91
. Central Illinois Public Svs. Co.	\$38.78	\$39.13
. Ohio Power Company (Ohio)	\$36.24	\$35.85
. Union Electric (St. Louis)	\$38.44	\$38.86
. Monongahela Power Co. (WV)	\$34.55	\$33.61
<u>Examples bills for utilities that have already reduced SO2 emissions</u>		
. Consolidated Edison (New York City)	\$62.35	\$63.74
. Long Island Lighting Co.	\$60.81	\$62.58
. Southern California Edison	\$43.10	\$49.63
. Pacific G&E (San Francisco)	\$45.73	\$51.31
. Orange & Rockland (New York)	\$58.87	\$60.44
. Commonwealth Edison (Illinois)	\$43.09	\$52.36
. Arizona Public Service Co.	\$47.62	\$48.83
. Connecticut L&P (Northeast Utilities)	\$47.56	\$49.15
. United Illuminating (Connecticut)	\$54.76	\$55.95

* Typical Electric Bills, U.S.DOE/EIA, Table 21 (DOE/EIA-0040(88)).

** Residential Electric Bills, Winter 1988-89, NARUC, January 10, 1990.

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Subject: Analysis of Acid Rain and updated
version of the preliminary analysis**ROUTE TO:****ACTION****DISPOSITION**

Office/Agency	(Staff Name)	Action Code	Tracking Date YY/MM/DD	Type of Response	Code	Completion Date YY/MM/DD
<u>CWofc</u>		ORIGINATOR	<u>10/01/23</u>			<u>1 1</u>
<u>Cuat 17</u>		Referral Note: <u>A</u>	<u>10/01/23</u>		<u>S</u>	<u>10/01/26</u>
<u>Cuat 02</u>		Referral Note: <u>I</u>	<u>1 1</u>			<u>1 1</u>
<u>Cugray</u>		Referral Note: <u>I</u>	<u>1 1</u>			<u>1 1</u>
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November 30, 1989

MEMORANDUM

TO: Rob Brenner, EPA

FROM: Bruce Braine, ICF Resources
Dina Kruger
Richard Stuebi

SUBJECT: Analysis of Acid Rain Options

This memorandum presents our preliminary analysis of eight proposed acid rain options. Please note that the results of this analysis should be considered approximate. The interactions between utility compliance choices, program costs, and coal market impacts are extremely complicated and warrant a detailed modelling effort (particularly when considering intertemporal emissions banking options). Because of time limitations, such an effort was not undertaken as part of this analysis. Thus, these estimates are based on extrapolations from previous analytic studies, not on detailed analysis of the specific options.

The following information is presented for each option:

- SO₂ Emission Reductions (below 1980 levels), both Cumulative (1990-2010) and Peak Year
- NO_x Emission Reductions (below base case levels), both Cumulative and Peak Year
- Present Value of Costs (through 2010)
- Change in Utility Annualized Costs (including levelized subsidies), on a national basis
- "Average" Levelized Utility Electricity Rate Impacts for seven key states (PA, WV, OH, IL, IN, KY, and MO) and the national average for 1996, 2001, 2005, and 2010

- **National Coal Market Impacts for Phase I (1996/1998) and Phase II (2001, 2005, and 2010),** including both national changes in production levels and national coal mining employment gains or losses.
- **High Sulfur Coal Market Impacts for Phase I (1996/1998) and Phase II (2001, 2005 and 2010),** as above for only the Midwestern and Northern Appalachian coal producing regions.

This memorandum includes the following information. First, our understanding of the options as they were analyzed is summarized in a table that compares their key features. The next two tables present the results of our analysis, one comparing emission and cost impacts for the options and the second comparing coal production/employment impacts.

DESCRIPTION OF OPTIONS

The eight options under consideration can be separated into two distinct groups. Under five of the proposals (referred to herein as the **107 Plant Options**), 107 powerplants would be affected in Phase I and these plants would be required to meet emission allowances based on their "baseline" fuel consumption multiplied by a 2.5 lb./mmBtu SO₂ emission rate during Phase I (beginning in 1996). The remaining three proposals take a different approach toward emission reductions. These options (referred to herein as the **Top 20 Plant Options**) achieve most of their reductions at the top-20 SO₂ emitting powerplants (which were identified based on their 1985 SO₂ emissions), and require these plants to meet a 1.1 lb./mmBtu emission rate. Each group of proposals is described in more detail below, and their key features are compared in Table 1.

The "107 Plant" Options

Under the five "107 plant" options, those powerplants with emission rates of more than 2.5 lbs/mmBtu and nameplate capacity of more than 100 MW would be required to meet emission allowances equal to a 2.5 lb/mmBtu SO₂ emission rate in Phase I (1996) multiplied by baseline (1985-1987) fuel consumption. Emissions trading would be allowed within utility systems. In Phase II, all affected units (larger than 75 MW and a 1985 emission rate higher than 1.2 lbs/mmBtu) would be required to meet a 1.2 lb rate. New units brought on line after 1985 would be required to purchase emission allowances to cover their SO₂ emissions. All unaffected units would be limited to their 1985 emission rates.

Differences between these options are discussed below.

- **"107 Plants/1:1 Credits":** Under this option, banking or emission reduction credits would be provided in Phase II for utilities that reduced emissions more than required in Phase I. These credits would be equal to the difference between the total allowances provided to "affected" sources in Phase I and emission levels achieved at these plants. Credits would be provided regardless of the compliance strategy pursued in Phase I.

- **"107 Plants/1:1 Credits and Early Reductions":** This proposal is very similar to the previous option except that it would also provide credits for "early reductions" (i.e., reductions made prior to the beginning of Phase I in 1996). These early reduction credits could be used in either Phase I or Phase II to offset required emission reductions.
- **"107 Plants/1:1 Credits and 2-year Technology Delay":** Under this option, all plants would receive 1:1 or single credits in Phase II for the additional reductions achieved in Phase I through either fuel switching or the use of technology. As above, plants that chose to install pollution control technology would be granted a two-year extension for compliance (until 1998).
- **"107 Plants/2:1 Credits":** This option is identical to the 1:1 credit option except that 2:1 (or "double") credits would be provided in Phase II for utilities that obtained extra reductions in Phase I. The double credits would equal twice the difference between the total allowances provided to the "affected" sources and the total emissions levels achieved at these plants.
- **"107 Plants/2:1 Technology Credits and 2-Year Technology Delay":** Under this option, double credits would only be provided for plants that chose to achieve extra reductions through the use of pollution control technologies (i.e., scrubbing). Single (1:1) credits would still be provided in Phase I for any extra Phase I reductions obtained through fuel switching. Only plants that chose to install pollution control technology in Phase I would receive double credits, however. These double credits would be measured as the difference between the scrubbed emission rate achieved and a 2.5 lb./mmBtu rate multiplied by 1996 fuel consumption. Plants that installed pollution control technology would also be granted a two-year extension for Phase I compliance (until 1998), which would provide additional time to install the scrubber, during which time reductions would not be required at the affected powerplants.

The "Top 20 Plant" Options

The "Top 20 Plant" options focus on only 20 plants in Phase I, instead of 107 plants, and require much larger reductions from them. Under these three options, only the 20 highest-SO₂ emitting powerplants (based on their 1985 emissions) would be required to meet certain requirements. Similar to the "107 Plant" options, emissions trading among affected sources would be permitted in Phase I across state lines and within utility systems. Moreover, these options would also require all oil plants to meet a 1.0 lb./mmBtu SO₂ emission rate in Phase I. Key differences between the three options are discussed below.

- **"Top 20 Plants/90% Subsidy with Generation Fee":** Under this option, the top 20 emitting powerplants would be required to meet a 1.1 lb./mmBtu emission rate in Phase I. Affected plants that chose to use pollution control technologies to reduce their emissions would receive a 90 percent capital subsidy, which would be funded through a 0.5 mill/kwh fee on all U.S. fossil generation from 1990 through 1996. In Phase II, this option would have the same requirements as the 107 Plant options described above.

- **"Top 20 Plants/90% Subsidy with SO₂ Emissions Fee"**: This option is identical to the previous option except that the subsidies would be funded through a fee of \$45/ton on all utility SO₂ emissions and a \$55/ton on all industrial SO₂ emissions, over the period 1990 to 1996.
- **"Top 20 Plants/2:1 Technology Credit, 2-Year Delay"**: Under this option, any affected plants that chose to use pollution control technology would be granted a two-year extension for Phase I compliance (until 1998) and would receive "double credits" in Phase II for the additional reductions achieved. These credits would be equal to twice the difference between a 1.1 lb/mmBtu annual SO₂ emission rate and a scrubbed emissions rate multiplied by their future fuel consumption. Credits would not be available for other non-technology compliance strategies. Utility holding companies could also substitute other plants and/or reductions in lieu of the top-20 plants. Under this option, the Phase II requirements would be identical to those described above for the 107 Plant options.

TABLE 1

**COMPARISON OF SELECTED FEATURES
OF ACID RAIN OPTIONS UNDER CONSIDERATION**

<u>OPTION</u>	<u>Subsidy/ Fee</u>	<u>Emissions Trading</u>	<u>Banking Credits for: Technology</u>	<u>Other</u>	<u>Technology Delay</u>	<u>1.0 Lb. Oil Limit</u>
107 Plant Options						
1:1 Credits	No	Yes	Yes-1:1	Yes-1:1	No	No
1:1 Credits/ Early Reductions	No	Yes	Yes-1:1	Yes-1:1	No	No
1:1 Credits/2-Yr Technology Delay	No	Yes	Yes-1:1	Yes-1:1	Yes	No
2:1 Credits	No	Yes	Yes-2:1	Yes-2:1	No	No
2:1 Technology Credits/2-Yr Technology Delay	No	Yes	Yes-2:1	Yes-1:1	Yes	No
Top 20 Plant Options						
90% Subsidy with Generation Fee	Yes	Yes	No	No	No	Yes
90% Subsidy with SO ₂ Emissions Fee	Yes	Yes	No	No	No	Yes
2:1 Technology Credits/2-Yr Delay	No	Yes	Yes-2:1	No	Yes	Yes

Table 2
Emission Reductions and Coal Market Impacts

	107 Plant Options				20 Plant Options			
	E1 Credits	E1 Credits/ Btu Reduction	1:1 Credits/ 2 Year Delay	2:1 Credits/ 2 Year Delay	SO ₂ For	SO ₂ Capital Subsidy	Gen. For	2 Year Delay
Utility Emission Reductions (millions of tons)								
SO ₂ Reductions (below 1990 levels)								
Cumulative (1990-2005)	94 - 109	94 - 109	94 - 109	87 - 105	3 - 54	91 - 115	28 - 105	21 Credits
Peak Year	8.3 - 8.9	8.3 - 8.9	8.3 - 8.9	8.1 - 8.9	8.7 - 8.9	8.7 - 8.9	8.7 - 8.9	2 Year Delay
NO _x Reductions (below base case levels)								
Cumulative (1990-2005)	19 - 22	19 - 22	19 - 22	19 - 22	19 - 22	19 - 22	19 - 22	2
Peak Year	2	2	2	2	2	2	2	2
Coal Production (millions of tons)								
Phase I (1990)	0 - 5	0 - 5	0 - 5	0 - 5	35 - 40	35 - 40	20	20
Phase II (2005)	10 - 20	10 - 15	10 - 20	0 - 12	35 - 40	35 - 40	20	20
National Coal Imports/Exports 1994/1995								
Job State (thousands)	—	—	—	—	—	—	—	—
Production (millions of tons)	—	—	—	—	—	—	—	—
Job State (thousands)	—	—	—	—	—	—	—	—
Production (millions of tons)	—	—	—	—	—	—	—	—
Job State (thousands)	—	—	—	—	—	—	—	—
Production (millions of tons)	—	—	—	—	—	—	—	—
Job State (thousands)	—	—	—	—	—	—	—	—
Production (millions of tons)	—	—	—	—	—	—	—	—
Regional Coal Imports/Exports 1994/1995								
Job State (thousands)	4 - 9	4 - 8	4 - 9	4 - 8	0 - 2	0 - 2	3 - 4	3 - 4
Production (millions of tons)	50 - 70	45 - 65	50 - 70	50 - 65	0 - 10	0 - 10	20 - 30	20 - 30
Job State (thousands)	13 - 15	13 - 14	13 - 15	13 - 14	10 - 13	10 - 13	13 - 14	13 - 14
Production (millions of tons)	90 - 105	80 - 100	90 - 105	85 - 100	70 - 90	70 - 90	90 - 100	90 - 100
Job State (thousands)	11 - 13	10 - 13	11 - 13	9 - 11	7 - 10	7 - 10	12 - 14	12 - 14
Production (millions of tons)	75 - 90	70 - 90	75 - 90	65 - 80	50 - 70	50 - 70	85 - 95	85 - 95
Job State (thousands)	11 - 15	11 - 14	11 - 15	11 - 14	8 - 11	8 - 11	11 - 16	11 - 16
Production (millions of tons)	40 - 60	40 - 60	40 - 60	40 - 60	35 - 75	35 - 75	40 - 60	40 - 60

1/ National coal production and national coal mining employment are not expected to decrease or increase significantly as a result of the alternative acid rain options.
2/ In Phase II, coal production impacts assume that only conventional technologies are used to achieve emissions reductions. The use of clean coal technologies is not assumed in these estimates.

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Table 3
Cost Impacts

Cost Impacts	107 Plant Options					20 Plant Options				
	1:1 Credits/ Early Reduction	1:1 Credits/ 2 Year Delay	2:1 Credits	2:1 Credits/ 2 Year Delay	2:1 Credits/ 2 Year Delay	SO ₂ Fee	90% Capital Subsidy	Gen. Fee	2:1 Credits/ 2 Year Delay	2:1 Credits/ 2 Year Delay
Present Value of Costs (then 2000) (billions of 1985 dollars)	12 - 18	12 - 17	12 - 18	12 - 17	12 - 17					
1996										
Annualized Costs (1985 \$/MWh) ^{1/} Levelized Rate Increases (%)	0.5 - 0.8	0.5 - 0.6	0.5 - 0.8	0.5 - 0.6	0.5 - 0.6					
PA	0.3 - 0.5	0.3 - 0.5	0.3 - 0.5	0.3 - 0.5	0.3 - 0.5					
WV	0.5 - 0.7	0.3 - 0.6	0.5 - 0.7	0.3 - 0.6	0.3 - 0.5					
OH	0.8 - 0.9	0.8 - 0.9	0.8 - 0.9	0.8 - 0.9	0.7 - 1.0					
KY	0.3 - 0.8	0.3 - 0.4	0.3 - 0.8	0.3 - 0.4	1.0 - 2.0					
IN	0.5 - 1.5	0.5 - 1.0	0.5 - 1.5	0.5 - 1.0	0.8 - 1.7					
IL	1.1 - 1.3	1.1 - 1.2	1.1 - 1.3	1.1 - 1.2	1.3 - 1.5					
MO	1.5 - 2.0	1.5 - 2.0	1.5 - 2.0	1.5 - 2.0	1.8 - 2.5					
National Average	0.2 - 0.4	0.2 - 0.3	0.2 - 0.4	0.2 - 0.3	0.2 - 0.3					
2001										
Annualized Costs (1985 \$/MWh) ^{1/} Levelized Rate Increases (%)	1.8 - 2.7	1.8 - 2.5	1.8 - 2.7	1.7 - 2.6	1.8 - 2.6					
PA	1.5 - 1.6	1.5 - 1.6	1.5 - 1.6	1.5 - 1.6	1.2 - 1.4					
WV	5.0 - 5.2	5.1 - 5.6	5.0 - 5.2	5.1 - 5.6	3.2 - 3.7					
OH	1.7 - 3.5	1.7 - 3.5	1.7 - 3.5	1.7 - 3.5	0.6 - 1.1					
KY	2.4 - 3.1	2.4 - 3.1	2.4 - 3.1	2.4 - 3.1	2.6 - 3.2					
IN	1.7 - 3.6	1.7 - 3.6	1.7 - 3.6	1.7 - 3.6	0.9 - 1.2					
IL	0.3 - 0.7	0.7 - 0.8	0.3 - 0.7	0.7 - 0.8	0.1 - 0.7					
MO	3.9 - 4.4	3.9 - 4.4	3.9 - 4.4	3.9 - 4.4	2.4 - 2.7					
National Average	1.1 - 1.2	1.1 - 1.2	1.1 - 1.2	1.1 - 1.2	0.9 - 1.2					
2005										
Annualized Costs (1985 \$/MWh) ^{1/} Levelized Rate Increases (%)	2.9 - 4.0	2.8 - 3.8	2.9 - 4.0	2.7 - 3.6	2.8 - 3.8					
PA	1.6 - 2.1	1.6 - 2.1	1.6 - 2.1	1.6 - 2.1	1.6 - 1.9					
WV	4.8 - 5.2	4.8 - 5.2	4.8 - 5.2	4.8 - 5.2	3.6 - 4.2					
OH	3.2 - 4.5	3.2 - 4.5	3.2 - 4.5	3.2 - 4.5	0.7 - 3.2					
KY	2.9 - 4.0	2.9 - 4.0	2.9 - 4.0	2.9 - 4.0	2.8 - 4.0					
IN	2.6 - 4.0	2.6 - 4.0	2.6 - 4.0	2.6 - 4.0	1.2 - 2.7					
IL	1.2 - 3.0	1.4 - 3.0	1.2 - 3.0	1.4 - 3.0	0.9 - 2.5					
MO	3.9 - 4.5	3.9 - 4.5	3.9 - 4.5	3.9 - 4.5	2.7 - 3.3					
National Average	1.6 - 1.8	1.5 - 1.7	1.6 - 1.8	1.5 - 1.7	1.3 - 1.7					
2009										
Annualized Costs (1985 \$/MWh) ^{1/} Levelized Rate Increases (%)	2.4 - 4.8	2.4 - 4.7	2.4 - 4.8	2.4 - 4.7	2.4 - 4.8					
PA	1.4 - 2.0	1.4 - 2.0	1.4 - 2.0	1.4 - 2.0	1.4 - 1.9					
WV	4.7 - 5.7	4.7 - 5.7	4.7 - 5.7	4.7 - 5.7	4.7 - 6.0					
OH	3.3 - 4.7	3.3 - 4.7	3.3 - 4.7	3.3 - 4.7	4.7 - 5.2					
KY	3.1 - 3.2	3.0 - 3.1	3.1 - 3.2	3.0 - 3.1	3.1 - 3.2					
IN	3.9 - 4.8	3.7 - 4.0	3.9 - 4.8	3.7 - 4.0	3.8 - 4.0					
IL	0.7 - 1.9	0.7 - 2.1	0.7 - 1.9	0.7 - 2.1	0.7 - 1.8					
MO	3.6 - 4.8	3.6 - 4.8	3.6 - 4.8	3.6 - 4.8	3.4 - 3.6					
National Average	1.2 - 1.8	1.2 - 1.7	1.2 - 1.8	1.2 - 1.7	1.2 - 1.8					

^{1/} Annualized costs include levelized subsidy costs where appropriate.

ICF RESOURCESSM

INCORPORATED



9300 Lee Highway, Fairfax, Va. 22031-1207 Phone: 703 934-3000 Fax: 703 691-3349 Telex: 440126 ICF UI

December 6, 1989

MEMORANDUM

TO: Rob Brenner, EPA

FROM: Bruce Braine, ICF Resources
Dina Kruger
Richard Stuebi

SUBJECT: Analysis of Acid Rain Options

This memorandum presents an updated version of our preliminary analysis of eight proposed acid rain options, prepared on November 30, 1989. The updated version contains revisions to national and some state level electricity rate impacts presented in Table 3. Please note that the results of this analysis should be considered approximate. The interactions between utility compliance choices, program costs, and coal market impacts are extremely complicated and warrant a detailed modelling effort (particularly when considering intertemporal emissions banking options). Because of time limitations, such an effort was not undertaken as part of this analysis. Thus, these estimates are based on extrapolations from previous analytic studies, not on detailed analysis of the specific options.

The following information is presented for each option:

- SO₂ Emission Reductions (below 1980 levels), both Cumulative (1990-2010) and Peak Year
- NO_x Emission Reductions (below base case levels), both Cumulative and Peak Year
- Present Value of Costs (through 2010)
- Change in Utility Annualized Costs (including levelized subsidies), on a national basis

- "Average" Levelized Utility Electricity Rate Impacts for seven key states (PA, WV, OH, IL, IN, KY, and MO) and the national average for 1996, 2001, 2005, and 2010
- National Coal Market Impacts for Phase I (1996/1998) and Phase II (2001, 2005, and 2010), including both national changes in production levels and national coal mining employment gains or losses.
- High Sulfur Coal Market Impacts for Phase I (1996/1998) and Phase II (2001, 2005 and 2010), as above for only the Midwestern and Northern Appalachian coal producing regions.

This memorandum includes the following information. First, our understanding of the options as they were analyzed is summarized in a table that compares their key features. The next two tables present the results of our analysis, one comparing emission and cost impacts for the options and the second comparing coal production/employment impacts.

DESCRIPTION OF OPTIONS

The eight options under consideration can be separated into two distinct groups. Under five of the proposals (referred to herein as the **107 Plant Options**), 107 powerplants would be affected in Phase I and these plants would be required to meet emission allowances based on their "baseline" fuel consumption multiplied by a 2.5 lb./mmBtu SO₂ emission rate during Phase I (beginning in 1996). The remaining three proposals take a different approach toward emission reductions. These options (referred to herein as the **Top 20 Plant Options**) achieve most of their reductions at the top-20 SO₂ emitting powerplants (which were identified based on their 1985 SO₂ emissions), and require these plants to meet a 1.1 lb./mmBtu emission rate. Each group of proposals is described in more detail below, and their key features are compared in Table 1.

The "107 Plant" Options

Under the five "107 plant" options, those powerplants with emission rates of more than 2.5 lbs/mmBtu and nameplate capacity of more than 100 MW would be required to meet emission allowances equal to a 2.5 lb/mmBtu SO₂ emission rate in Phase I (1996) multiplied by baseline (1985-1987) fuel consumption. Emissions trading would be allowed within utility systems. In Phase II, all affected units (larger than 75 MW and a 1985 emission rate higher than 1.2 lbs/mmBtu) would be required to meet a 1.2 lb rate. New units brought on line after 1985 would be required to purchase emission allowances to cover their SO₂ emissions. All unaffected units would be limited to their 1985 emission rates.

Differences between these options are discussed below.

- **"107 Plants/1:1 Credits":** Under this option, banking or emission reduction credits would be provided in Phase II for utilities that reduced emissions more than required in Phase I. These credits would be equal to the difference between the total allowances provided

to "affected" sources in Phase I and emission levels achieved at these plants. Credits would be provided regardless of the compliance strategy pursued in Phase I.

- **"107 Plants/1:1 Credits and Early Reductions":** This proposal is very similar to the previous option except that it would also provide credits for "early reductions" (i.e., reductions made prior to the beginning of Phase I in 1996). These early reduction credits could be used in either Phase I or Phase II to offset required emission reductions.
- **"107 Plants/1:1 Credits and 2-year Technology Delay":** Under this option, all plants would receive 1:1 or single credits in Phase II for the additional reductions achieved in Phase I through either fuel switching or the use of technology. As above, plants that chose to install pollution control technology would be granted a two-year extension for compliance (until 1998).
- **"107 Plants/2:1 Credits":** This option is identical to the 1:1 credit option except that 2:1 (or "double") credits would be provided in Phase II for utilities that obtained extra reductions in Phase I. The double credits would equal twice the difference between the total allowances provided to the "affected" sources and the total emissions levels achieved at these plants.
- **"107 Plants/2:1 Technology Credits and 2-Year Technology Delay":** Under this option, double credits would only be provided for plants that chose to achieve extra reductions through the use of pollution control technologies (i.e., scrubbing). Single (1:1) credits would still be provided in Phase I for any extra Phase I reductions obtained through fuel switching. Only plants that chose to install pollution control technology in Phase I would receive double credits, however. These double credits would be measured as the difference between the scrubbed emission rate achieved and a 2.5 lb./mmBtu rate multiplied by 1996 fuel consumption. Plants that installed pollution control technology would also be granted a two-year extension for Phase I compliance (until 1998), which would provide additional time to install the scrubber, during which time reductions would not be required at the affected powerplants.

The "Top 20 Plant" Options

The "Top 20 Plant" options focus on only 20 plants in Phase I, instead of 107 plants, and require much larger reductions from them. Under these three options, only the 20 highest-SO₂ emitting powerplants (based on their 1985 emissions) would be required to meet certain requirements. Similar to the "107 Plant" options, emissions trading among affected sources would be permitted in Phase I across state lines and within utility systems. Moreover, these options would also require all oil plants to meet a 1.0 lb./mmBtu SO₂ emission rate in Phase I. Key differences between the three options are discussed below.

- **"Top 20 Plants/90% Subsidy with Generation Fee":** Under this option, the top 20 emitting powerplants would be required to meet a 1.1 lb./mmBtu emission rate in Phase I, or 90 percent removal if they choose to scrub. If affected plants chose to use pollution control technologies to reduce their emissions, they would receive a 90 percent capital subsidy, which would be funded through a 0.5 mill/kwh fee on all U.S. fossil

generation from 1990 through 1996. Phase II, this option would have the same requirements as the 107 Plant options described above.

- **"Top 20 Plants/90% Subsidy with SO₂ Emissions Fee":** This option is identical to the previous option except that the subsidies would be funded through a fee of \$45/ton on all utility SO₂ emissions and a \$55/ton on all industrial SO₂ emissions, over the period 1990 to 1996.
- **"Top 20 Plants/2:1 Technology Credit, 2-Year Delay":** Under this option, any affected plants that chose to use pollution control technology would be granted a two-year extension for Phase I compliance (until 1998) and would receive "double credits" in Phase II for the additional reductions achieved. These credits would be equal to twice the difference between a 1.1 lb/mmBtu annual SO₂ emission rate and a scrubbed emissions rate multiplied by their future fuel consumption. Credits would not be available for other non-technology compliance strategies. Utility operating companies could also substitute other plants and/or reductions in lieu of the top-20 plants. Under this option, the Phase II requirements would be identical to those described above for the 107 Plant options.

TABLE 1

**COMPARISON OF SELECTED FEATURES
OF ACID RAIN OPTIONS UNDER CONSIDERATION**

<u>OPTION</u>	<u>Subsidy/ Fee</u>	<u>Emissions Trading</u>	<u>Banking Credits for: Technology</u>	<u>Other</u>	<u>Technology Delay</u>	<u>1.0 Lb. Oil Limit</u>
107 Plant Options						
1:1 Credits	No	Yes	Yes-1:1	Yes-1:1	No	No
1:1 Credits/ Early Reductions	No	Yes	Yes-1:1	Yes-1:1	No	No
1:1 Credits/2-Yr Technology Delay	No	Yes	Yes-1:1	Yes-1:1	Yes	No
2:1 Credits	No	Yes	Yes-2:1	Yes-2:1	No	No
2:1 Technology Credits/2-Yr Technology Delay	No	Yes	Yes-2:1	Yes-1:1	Yes	No
Top 20 Plant Options						
90% Subsidy with Generation Fee	Yes	Yes	No	No	No	Yes
90% Subsidy with SO ₂ Emissions Fee	Yes	Yes	No	No	No	Yes
2:1 Technology Credits/2-Yr Delay	No	Yes	Yes-2:1	No	Yes	Yes

Table 2
Emission Reductions and Coal Market Impacts

	107 Plant Options				20 Plant Options			
	1:1 Credits	1:1 Credits/ Early Reduction	1:1 Credits/ 2 Year Delay	2:1 Credits	SO ₂ Fee	90% Capital Subsidy Gen. Fee	2:1 Credits 2 Year Delay	
Utility Emission Reductions (millions of tons)								
SO ₂ Reductions (below 1980 levels) Cumulative (1990-2010) Peak Year	94 - 109 8.3 - 8.9	94 - 109 8.1 - 8.9	94 - 109 8.3 - 8.9	87 - 105 8.1 - 8.9	97 - 115 8.7 - 8.9		88 - 103 8.7 - 8.9	
NO _x Reductions (below base case levels) Cumulative (1990-2010) Peak Year	19 - 22 2	19 - 22 2	19 - 22 2	19 - 22 2	19 - 22 2		19 - 22 2	
Compliance Choices								
Retrofit Scrubber Capacity (gw) Phase I (1996) Phase II (2005)	0 - 5 10 - 20	0 - 5 10 - 15	0 - 5 10 - 20	0 - 5 8 - 12	35 - 40 35 - 40		20 20	
National Coal Impacts ^{1/2/} 1996/1998								
Job Slots (thousands) Production (millions of tons)	— —	— —	— —	— —	— —		— —	
2001								
Job Slots (thousands) Production (millions of tons)	— —	— —	— —	— —	— —		— —	
2005								
Job Slots (thousands) Production (millions of tons)	— —	— —	— —	— —	— —		— —	
2010								
Job Slots (thousands) Production (millions of tons)	— —	— —	— —	— —	— —		— —	
N. Appalachia/Midwest Coal Impacts ^{2/} 1996/1998								
Job Slots (thousands) Production (millions of tons)	-6 - -9 -50 - -70	-6 - -8 -45 - -65	-6 - -9 -50 - -70	-6 - -8 -50 - -65	0 - -2 0 - -10		-3 - -4 -20 - -30	
2001								
Job Slots (thousands) Production (millions of tons)	-13 - -15 -90 - -105	-13 - -14 -90 - -100	-13 - -15 -90 - -105	-12 - -14 -85 - -100	-10 - -13 -70 - -90		-13 - -14 -90 - -100	
2005								
Job Slots (thousands) Production (millions of tons)	-11 - -13 -75 - -90	-10 - -13 -70 - -90	-11 - -13 -75 - -90	-9 - -11 -65 - -80	-7 - -10 -50 - -70		-12 - -14 -85 - -95	
2010								
Job Slots (thousands) Production (millions of tons)	-11 - -15 -80 - -105	-11 - -14 -80 - -100	-11 - -15 -80 - -105	-11 - -14 -80 - -100	-8 - -11 -55 - -75		-11 - -16 -80 - -110	

1/ National coal production and national coal mining employment are not expected to decrease or increase significantly as a result of the alternative acid rain options.

2/ In Phase II, coal production impacts assume that only conventional technologies are used to achieve emissions reductions. The use of clean coal technologies is not assumed in these estimates.

Table 3
Cost Impacts

Cost Impacts	107 Plant Options				20 Plant Options			
	1:1 Credits/ Early Reduction		2:1 Credits/ 2 Year Delay		90% Capital Subsidy SO ₂ Fee		Gen. Fee 2 Year Delay	
	1:1 Credits	12 - 18	12 - 17	12 - 18	11 - 16	12 - 17	20 - 26	15 - 19
Percent Value of Costs (thru 2010) (billions of 1988 dollars)								
1996/1988								
Annualized Costs (1988\$ billion/yr) ^{1/}	0.5 - 0.8	0.5 - 0.8	0.5 - 0.6	0.5 - 0.8	0.5 - 0.6	0.5 - 0.6	1.6 - 1.8	1.1 - 1.2
Levelized Rate Increases (%)								
PA	0.3 - 0.5	0.3 - 0.5	0.3 - 0.5	0.3 - 0.5	0.3 - 0.5	0.4 - 0.5	1.3 - 1.5	1.3 - 1.5
WV	0.5 - 0.7	0.5 - 0.7	0.3 - 0.6	0.3 - 0.7	0.3 - 0.6	0.7 - 0.8	2.6 - 2.7	2.8 - 3.0
OH	0.8 - 0.9	0.8 - 0.9	0.8 - 0.9	0.8 - 0.9	0.8 - 0.9	1.2 - 1.6	2.5 - 2.6	5.1 - 5.4
KY	0.3 - 0.8	0.3 - 0.8	0.3 - 0.4	0.3 - 0.8	0.3 - 0.4	0.3 - 0.4	5.3 - 5.5	0.0
IN	0.5 - 1.5	0.5 - 1.5	0.5 - 1.0	0.5 - 1.5	0.5 - 1.0	1.0 - 1.1	1.0 - 1.3	1.1 - 1.3
IL	1.1 - 1.3	1.1 - 1.3	1.1 - 1.2	1.1 - 1.3	1.1 - 1.2	1.0 - 1.1	2.7 - 3.5	1.0 - 1.1
MO	1.5 - 1.8	1.5 - 1.8	1.5 - 1.8	1.5 - 1.8	1.5 - 1.8	1.7 - 2.3	1.1 - 1.2	0.4 - 0.7
National Average	0.2 - 0.4	0.2 - 0.4	0.2 - 0.3	0.2 - 0.4	0.2 - 0.3	0.2 - 0.3	3.0 - 3.2	0.5 - 0.6
2001								
Annualized Costs (1988\$ billion/yr) ^{1/}	1.8 - 2.7	1.8 - 2.7	1.8 - 2.5	1.8 - 2.7	1.7 - 2.6	1.8 - 2.6	2.4 - 3.7	2.1 - 3.0
Levelized Rate Increases (%)								
PA	1.5 - 1.6	1.5 - 1.6	1.5 - 1.6	1.5 - 1.6	1.5 - 1.6	1.2 - 1.6	1.2 - 1.3	1.0 - 1.1
WV	5.0 - 5.2	5.1 - 5.6	5.1 - 5.6	5.0 - 5.2	5.1 - 5.6	3.6 - 3.8	4.4 - 5.0	4.2 - 4.5
OH	1.7 - 3.5	1.7 - 3.5	1.7 - 3.5	1.7 - 3.5	1.7 - 3.5	0.6 - 0.8	1.5 - 2.6	1.6 - 2.0
KY	2.4 - 3.1	2.4 - 3.1	2.4 - 3.1	2.4 - 3.1	2.4 - 3.1	2.6 - 3.2	3.1 - 3.5	3.3 - 3.5
IN	1.7 - 3.6	1.7 - 3.6	1.5 - 3.6	1.7 - 3.6	1.6 - 3.6	0.5 - 1.2	3.3 - 3.7	3.3 - 3.5
IL	0.3 - 0.7	0.3 - 0.7	0.7 - 0.8	0.3 - 0.7	0.7 - 0.8	0.1 - 0.7	0.4 - 0.7	0.2 - 0.4
MO	3.9 - 4.4	3.9 - 4.4	3.9 - 4.4	3.9 - 4.4	3.9 - 4.4	2.4 - 2.6	3.6 - 4.4	3.9 - 4.4
National Average	0.9 - 1.2	0.9 - 1.2	0.9 - 1.1	0.9 - 1.2	0.9 - 1.1	0.9 - 1.1	1.0 - 1.5	1.0 - 1.4
2005								
Annualized Costs (1988\$ billion/yr) ^{1/}	2.9 - 4.0	2.9 - 4.0	2.8 - 3.8	2.9 - 4.0	2.7 - 3.6	2.8 - 3.8	3.6 - 4.4	3.5 - 4.1
Levelized Rate Increases (%)								
PA	1.6 - 2.1	1.6 - 2.1	1.6 - 2.1	1.6 - 2.1	1.6 - 2.1	1.4 - 1.9	1.3 - 1.7	1.6 - 2.0
WV	4.8 - 5.2	4.8 - 5.2	4.8 - 5.2	4.8 - 5.2	4.8 - 5.2	3.6 - 4.1	4.1 - 4.8	5.0 - 5.7
OH	3.2 - 4.5	3.2 - 4.5	3.2 - 4.5	3.2 - 4.5	3.2 - 4.5	0.9 - 2.5	2.3 - 3.8	3.7 - 5.0
KY	2.9 - 4.0	2.9 - 4.0	2.6 - 4.0	2.9 - 4.0	2.3 - 4.0	2.7 - 4.0	3.4 - 3.9	3.4 - 3.9
IN	3.2 - 4.0	3.2 - 4.0	2.6 - 4.0	3.2 - 4.0	1.9 - 4.0	1.4 - 2.2	3.5 - 3.9	3.8 - 4.0
IL	1.2 - 3.0	1.2 - 3.0	1.4 - 3.0	1.2 - 3.0	1.4 - 3.0	0.8 - 3.0	1.3 - 2.6	1.7 - 3.1
MO	3.9 - 4.5	3.9 - 4.5	3.9 - 4.5	3.9 - 4.5	3.9 - 4.5	2.6 - 3.5	3.9 - 4.5	3.9 - 4.5
National Average	1.5 - 1.7	1.5 - 1.7	1.5 - 1.6	1.5 - 1.7	1.4 - 1.5	1.5 - 1.7	1.6 - 1.8	1.7 - 1.9
2010								
Annualized Costs (1988\$ billion/yr) ^{1/}	2.4 - 4.8	2.4 - 4.8	2.4 - 4.7	2.4 - 4.8	2.4 - 4.7	2.4 - 4.8	2.6 - 5.4	2.4 - 5.1
Levelized Rate Increases (%)								
PA	1.4 - 2.0	1.4 - 2.0	1.4 - 2.0	1.4 - 2.0	1.4 - 2.0	1.4 - 1.9	1.1 - 1.7	1.4 - 2.0
WV	4.7 - 5.7	4.7 - 5.7	4.7 - 6.0	4.7 - 5.7	4.7 - 6.0	4.7 - 5.2	4.0 - 5.4	5.0 - 6.3
OH	3.3 - 4.7	3.3 - 4.7	3.3 - 4.7	3.3 - 4.7	3.3 - 4.7	3.3 - 3.7	2.4 - 4.2	3.8 - 5.5
KY	3.1 - 3.2	3.1 - 3.2	2.9 - 3.1	3.1 - 3.2	2.9 - 3.1	3.1 - 3.2	3.1 - 3.6	3.1 - 3.6
IN	3.9 - 4.0	3.9 - 4.0	3.7 - 4.0	3.9 - 4.0	3.7 - 4.0	3.8 - 4.0	3.7 - 4.6	4.0 - 4.7
IL	0.7 - 1.9	0.7 - 1.9	0.7 - 2.1	0.7 - 1.9	0.7 - 2.1	0.7 - 1.8	0.5 - 2.0	1.0 - 2.3
MO	3.6 - 4.0	3.6 - 4.0	3.6 - 4.0	3.6 - 4.0	3.6 - 4.0	3.4 - 3.6	3.3 - 4.0	3.6 - 4.0
National Average	1.2 - 1.8	1.2 - 1.8	1.2 - 1.7	1.2 - 1.8	1.2 - 1.7	1.2 - 1.8	1.2 - 1.8	1.2 - 1.9

^{1/} Annualized costs include levelized subsidy costs where appropriate.

THE WHITE HOUSE

WASHINGTON

January 11, 1990

MEMORANDUM FOR THE FILE

FROM: JEFFREY R. HOLMSTEAD *JRH*
ASSISTANT COUNSEL TO THE PRESIDENT

SUBJECT: Status of Acid Rain Amendments and Other Emission
Trading Provisions

I have reviewed the above-referenced document, which will be used in on-going discussions regarding the President's proposed amendments to the Clean Air Act. No further action is necessary.

CLEAN AIR. 1

Subject:

Clean Air Act

Acid Rain

WHITE HOUSE CORRESPONDENCE TRACKING WORKSHEET

☐ O - OUTGOING☐ H - INTERNAL☐ I - INCOMINGDate Correspondence
Received (YY/MM/DD) 1 1Name of Correspondent: Richard B. Stewart☐ MI Mail Report

User Codes: (A) _____ (B) _____ (C) _____

Subject: Status of Acid Rain Amendments
and Other Emission Trading Provisions**ROUTE TO:****ACTION****DISPOSITION**

Office/Agency	(Staff Name)	Action Code	Tracking Date YY/MM/DD	Type of Response	Code	Completion Date YY/MM/DD
<u>Cuoco</u>		ORIGINATOR	<u>89/12/21</u>			<u>1 1</u>
<u>Walt 11</u>		Referral Note: <u>X</u>	<u>89/12/21</u>			<u>89/12/22</u>
<u>Walt 02</u>		Referral Note: <u>I</u>	<u>1 1</u>			<u>1 1</u>
<u>Gray</u>		Referral Note: <u>I</u>	<u>1 1</u>			<u>1 1</u>
		Referral Note: <u>-</u>	<u>1 1</u>			<u>1 1</u>
		Referral Note:				

ACTION CODES:

A - Appropriate Action
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I - Info Copy Only/No Action Necessary
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U.S. Department of Justice
Land and Natural Resources Division

Office of the Assistant Attorney General

Washington, D.C. 20530

December 21, 1989

MEMORANDUM

To: C. Boyden Gray
Counsel to the President

From: Richard B. Stewart *RS*
Assistant Attorney General

Subject: Status of Acid Rain Amendments and Other Emission
Trading Provisions

As you requested, we have been following closely the legislative developments on the emissions trading scheme which the Administration put forth in the Acid Rain title of the Clean Air bill. At the completion of the first session of the 101st Congress, this is the status of the acid rain provisions:

In the House, the Dingell/Lent substitute, introduced September 19 to modify and "perfect" the Administration bill, was approved by Rep. Waxman's Health and Environment Subcommittee on October 11. The acid rain provisions of the original Administration proposal were essentially unchanged.

The House bill (which is still designated HR 3030) is now stalled in Rep. Sharp's Energy and Power Subcommittee, which has obtained a referral of the bill's acid rain title. There is considerable opposition to the acid rain title there and in the full Energy and Commerce Committee. Sharp and other midwesterners are unhappy with the absence of "cost-sharing" provisions to ease the burden of acid rain controls on their region's high sulfur coal-burning utilities. Representatives from states such as Florida, California, and Utah, which have relatively clean utilities and high projected growth, are also unhappy with the bill. They think it is unfair that their utilities will have to purchase allowances, most likely from the midwest, to accommodate growth. Both factions are skeptical that HR 3030's allowance trading system will perform as advertised and create a viable market in allowances.

Committee Chairman Dingell recently circulated his own acid rain proposal, which he claims would maintain HR 3030's 10 million ton emissions cap and the allowance trading system while adding a per-ton emissions fee and subsidies for the hardest-hit

utilities. During the recess, Sharp is expected to work with Dingell to try to get him to expand his cost-sharing provisions. At hearings of the Health and Environment and Energy and Power subcommittees, Administration representatives have consistently stated that they are opposed to any cost-sharing beyond the allowance trading already in HR 3030¹, but Dingell, Sharp and others will undoubtedly push hard to get the Administration to compromise on this issue.

We have no information on when the bill will go to the full Committee, or what Dingell's plans and schedule will be once he gets it.

In the Senate, the Environment and Public Works Committee passed a massive clean air package (S 1630) by a vote of 15-1 after a single, day-long markup session on November 16. Majority Leader George Mitchell has promised the bill will be the "first order of business" before the full Senate when it reconvenes January 23.

The committee bill includes a recently introduced acid rain title (which is a modified version of the Administration acid rain proposal) as well as titles dealing with nonattainment, stratospheric ozone protection, air toxics, and municipal incinerators. Permit and enforcement provisions closely modeled after the Administration bill were also added.

The committee acid rain title would require a two-phase, 10-million-ton reduction in annual sulfur dioxide emissions and a 2-million-ton reduction in nitrogen oxides by 2000, compared with 1980 levels. Like the Administration bill, the committee bill

¹ The allowance trading system in HR 3030 can fairly be characterized as including a modest amount of cost sharing, although not in the form of the outright tax and subsidy sought by Sharp, Dingell and others. Under HR 3030, sources whose baseline emission rates are above 1.2 pounds of SO₂ per million Btus of fuel will get allowances equal to the amount their SO₂ emissions would be if they achieved a 1.2 lbs/mBtu rate, while sources that are currently operating at rates below 1.2 will not be given allowances for the difference between their current rates and 1.2 lbs/mBtu (although they can increase their utilization at the facility without limit as long as they don't exceed their baseline rate). Such low emission-rate sources will have to purchase allowances for additional emissions, even though they may be operating at lower emission rates than other sources. The effect of this provision will be to shift some of the costs of emission control from high emission-rate utilities to low emission-rate utilities, but the total dollar value of this shift will be small relative to the overall costs of the acid rain program.

includes an allowance trading system, and new power plants that emit SO2 after the year 2000 would have to obtain allowances to ensure offsetting emissions reductions.

The Senate committee bill differs in a number of respects from the Administration bill. It would shorten deadlines for reducing emissions by one year, and require greater NOx reductions. It also makes numerous minor adjustments in the requirements for various subcategories of SO2 sources.

The committee bill includes an interesting provision designed to create a fail-safe mechanism for the emissions allowance market. Under this provision, EPA would reserve for itself 2 percent of the total pool of emissions allowances, and act as a seller of last resort for buyers unable to obtain allowances on the open market. The price for these allowances, \$1,500 per ton, is purposely high to avoid undercutting the market. This proposal was developed by EPA in an effort to quell congressional criticism of the allowance trading system.

Another provision in the committee bill is a requirement for each federal agency with facilities that are served by utilities required to make SO2 reductions to use renewable and alternative clean-energy technologies to satisfy at least 10 percent of total electrical needs for the agency's facilities in that utility service area. Those facilities would also be required to make all cost-effective electricity conservation improvements. The stated purposes of this provision are to foster the development of alternative energy technologies and to assist the utilities that serve these facilities in meeting their SO2 requirements.

While the Senate committee's acid rain title embraces the concept of emissions trading, the committee's non-attainment title includes a new definition of "source" that effectively overrules an existing emissions trading mechanism, the bubble policy. The Senate committee has long opposed this policy. Under the policy, an entire facility consisting of multiple emission points may be considered a single source (or placed under a "bubble"). Trading of emissions and emission offsets among the different emission points is permitted so long as the net emissions from the facility do not increase. The bubble policy was upheld by the Supreme Court in Chevron v. NRDC, 104 S. Ct. 2778 (1984). EPA and DOJ consider it an important regulatory innovation in the use of emissions trading as a means of reducing the cost of emission reductions, and we plan to argue strongly against the provision eliminating bubbles in the Administration report on the bill.

Despite the Senate committee's quick action and lopsided vote, there is still considerable disagreement in the committee and the full Senate over many provisions of the bill, including the acid rain title. As in the House, that title is opposed by

growth-state Senators who view the bill's cap as a limit on growth, and midwesterners who want cost-sharing. Senators Mitchell, Baucus (chairman of the environmental protection subcommittee) and Chafee (the full committee's ranking minority member) have promised the dissidents they will work with them over the recess to develop a consensus committee amendment. The Senators will probably do a lot of negotiating in the next few weeks, and a long hard floor battle is expected when the bill finally comes to the floor.

ID # 089364 CU

WHITE HOUSE CORRESPONDENCE TRACKING WORKSHEET

☐ O - OUTGOING☐ H - INTERNAL☐ I - INCOMINGDate Correspondence
Received (YY/MM/DD) 1/1Name of Correspondent: Steven R. Schleicher☐ MI Mail Report

User Codes: (A) _____ (B) _____ (C) _____

Subject: Mailed 12/19/98 letter from the House
Energy and Commerce Committee re: potential
adverse job impacts of the President's and
panel proposal

ROUTE TO:

ACTION

DISPOSITION

Office/Agency	(Staff Name)	Action Code	Tracking Date YY/MM/DD	Type of Response	Code	Completion Date YY/MM/DD
	<u>Wage</u>	ORIGINATOR	<u>89/1/18</u>	<u>TR</u>	-	<u>1/1</u>
	<u>Chat 17</u>	Referral Note:	<u>89/1/18</u>			<u>89/1/19</u>
		Referral Note:	<u>1/1</u>			<u>1/1</u>
		Referral Note:	<u>1/1</u>			<u>1/1</u>
		Referral Note:	<u>1/1</u>			<u>1/1</u>
		Referral Note:	<u>1/1</u>			<u>1/1</u>

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Comments: No response required. JRH 2/14/90

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CAA - Acryl

Rain



Glenn R. Schleede
President

089364CM
New England Energy Incorporated
25 Research Drive
Westborough, Massachusetts 01582
Tel. (617) 366-9011 TWX 710-390-0732
Cable: NEELECSYS WTBO

November 6, 1989

The Honorable Elizabeth Hanford Dole
Secretary of Labor
200 Constitution Avenue, N.W.
Washington, D. C. 20210

Dear Secretary Dole:

An October 12, 1989 letter from the House Energy and Commerce Committee asks that you undertake certain actions with respect to potential adverse job impacts of the President's acid rain proposals. This letter, in brief:

- . Provides information that should be useful to you in your study, including some data indicating that proposed sulfur dioxide (SO₂) emission limits may result in a net gain in coal miner employment.
- . Urges that your study and response be comprehensive, specifically taking into account:
 - . The adverse employment impact throughout the U.S. of alternatives to the President's proposal, such as the tax on electric customers that has been proposed to raise money for subsidies to high emitting utilities to install scrubbers.
 - . The real national cost per job saved if such a tax and subsidy program were established.

ADDITIONAL DATA ON SO₂ EMISSIONS AND COAL MINING EMPLOYMENT.

As you proceed with your analysis, several points with respect to the issue of potential job loss as a result of measures to reduce sulfur dioxide (SO₂) emissions should be of interest:

1. Ten states are the principal sources of SO₂ emissions. There is no question that the largest quantities of remaining SO₂ emissions are coming from utilities burning relatively low cost high sulfur coal. NAPAP data indicate that about 70% of SO₂ emissions in 1985 came from electric utilities.
 - a. Some states have cleaned up and paid costs. During the past 20 years, some states and utilities have reduced SO₂ emissions, either by switching to low sulfur fuel or installing "scrubbers." Electric customers in these areas have paid billions to accomplish the reductions. They will be paying more in those states that have recently established tighter emission limits (e.g., Massachusetts,

New Hampshire, Minnesota, Wisconsin and New York), and they will be paying even more when new Federal acid rain legislation takes effect and the prices of low sulfur fuel are bid up.

- b. Ten states account for the majority of remaining SO2 emissions. In fact, National Coal Association (NCA) data on 1987 emissions from coal-fired power plants indicate that 10 states accounted for over 70% of all SO2 emitted from coal-fired power plants (10.4 million out of 14.8 million tons). Ten utility systems, often using low cost high sulfur coal, accounted for over 50% of SO2 emissions from coal-fired plants. (Attachments 1 and 2).

The NCA has not yet released its analysis of 1988 SO2 emissions from coal-fired power plants, but it appears that such emissions increased by some 400,000 tons, largely in high emission states.

In short, there are more states and utility systems with low SO2 emissions than high SO2 emissions.

- c. Estimates differ on potential coal mining job losses and gains. The data provided by EPA are but one set of estimates of the potential coal mining job losses and gains that might result from acid rain controls. Such estimates are highly dependent upon assumptions about feasibility, difficulty and cost of installing scrubbers; availability and future cost of high and low sulfur coal; and future cost of coal transportation.

Valid studies of coal mining job impact point out that losses in one area will be offset in whole or in part by gains in other areas.

Attachment #3 is an analysis of coal mining job losses and gains released in April 1989 by Energy Ventures Analysis, a group of coal experts located in Arlington, Virginia. This analysis identifies areas, makes estimates of losses and gains, and explains why its estimates differ from others, including those being used by EPA.

It's important to note that the EVA study estimates a net gain in coal mining jobs as a result of acid rain legislation. The largest gains would come in Central Appalachian regions.

- d. Coal mining job losses are principally due to productivity gains. As you study the coal mining job issue, it is important to recognize a large number of coal mining jobs (perhaps 100,000) have been eliminated because of substantial coal industry productivity improvements. Potential job gains and losses due to acid rain controls, while important, will be smaller than the numbers affected by productivity improvements.
- e. Job impacts of proposed tax and subsidy programs should also be taken into account. The principal option offered to date by those expressing concern about possible mining job losses is a nationwide tax on electricity generation and imports (e.g., HR 2909 and HR 1470.) The revenue would be used to provide subsidies to high

emitting utilities to pay costs of installing scrubbers so that those utilities would continue using high sulfur coal. Several aspects of such proposals deserve attention as you consider acid rain employment impacts:

- 1) First, even without Federal subsidies, scrubbers will be the economic choice for many power plants. Thus, subsidies are not necessary in those cases to help protect coal miners' jobs.
- 2) Second, proposed new nationwide taxes (being considered in the Congress) would cause job losses in areas from which the tax is collected. These job losses should also be taken into account in your study. For example, a 1 mill per kilowatthour (KWH) tax on all electric generation and imports -- really a tax paid by electric customers through their monthly bills -- would:
 - . Drain about \$97 million per year from the 6-state New England region (nearly \$1 billion over the 10-year period proposed for the tax).
 - . Drain about \$190 million per year from California.
 - . Drain about \$216 million per year from Texas.
 - . Drain about \$122 million per year from Florida.

These are just examples. A 1-mill tax would drain hundreds of millions each year from other low SO2 emitting areas.

This outflow of tax dollars would, of course, mean less economic activity and job losses in tax-paying regions. Of course, many of the jobs lost in low emission regions as a result of a tax would be union jobs.

The job loss situation in the tax-paying regions would be exacerbated by the fact that businesses in those areas would be relatively less competitive because they would now be paying more for electricity. In many cases, electricity costs are already higher in low emitting areas because customers in those areas are already paying through their monthly bills for the cost of low sulfur fuel or scrubbers -- while high emitting areas are enjoying the lower cost of high sulfur coal.

In summary, your study should not be limited to potential adverse effects of the President's proposal in certain areas. Instead, it should take into account the job loss impact nationwide of the proposed tax and subsidy proposals. Also, as indicated above, it should take into account coal mining job gains, not just potential coal mining job losses.

- f. Illinois presents a classic example of the potential employment effects of proposed tax and subsidy programs. In Illinois, Commonwealth Edison, which provides electricity to over half the people of Illinois, has sharply reduced its SO2 emissions from coal-fired power plants by using high cost low sulfur coal. Commonwealth Edison customers in Chicago and other areas served by the Company are paying the costs of reduced emissions. Most other utilities in Illinois continue to use low cost high sulfur coal.

A tax and subsidy program would mean that the 3.1 million Commonwealth Edison customers in Illinois would be paying a tax (over \$70 million per year under a 1-mill tax) to provide subsidies to others in the state (and possibly some outside Illinois). A tax and subsidy program may help protect some high sulfur coal miner jobs, but it would cost jobs in Chicago and other regions served by Commonwealth Edison.

THE STUDY SHOULD TAKE INTO ACCOUNT INEFFICIENCIES AND HIDDEN COSTS OF PROPOSALS TO TAX ELECTRIC CUSTOMERS TO PROVIDE SUBSIDIES TO HIGH EMITTING UTILITIES TO INSTALL SCRUBBERS.

The President's proposal of freedom to choose the most cost-effective approach to emission reduction and adherence to the "polluter pays" principle assures that inefficiencies would be minimized. If alternatives -- such as a nationwide tax and subsidies for high emitters -- are to be considered by the Congress, your study should take into account the inefficiencies and hidden costs that would result. Your study should take into account:

- . The likelihood that some utilities eligible to receive subsidies would elect or be required to install scrubbers when this action is not the most cost-effective way of reducing SO₂ emissions -- compared to switching to lower sulfur fuel.
- . A new tax and subsidy program would require a bureaucracy in Washington to administer the program. The administering group would have to identify qualifying recipients, evaluate and approve plans and cost estimates, approve selection of architect-engineer and construction contractors, monitor expenditures to avoid unwarranted charges or excessive spending. (Experience with other subsidy programs certainly has demonstrated the need for such steps, since recipients of subsidies have less incentive to make the most economic choices and to control expenditures when a significant share of costs are being paid from tax dollars, not revenue from customers.)

While such a program may create new jobs in government, the important point for your study is that the costs of administration should be taken into account. Those costs will mean higher taxes (with adverse job impact), less funds for subsidy recipients or the need for offsetting cuts in other programs.

WOULD IT BE MORE COSTLY TO PROTECT A COAL MINING JOB THROUGH A TAX AND SUBSIDY PROGRAM TO ENCOURAGE INSTALLATION OF SCRUBBERS THAN THROUGH OTHER ALTERNATIVES?

As indicated above, a tax or subsidy program would lead or require some utilities to install scrubbers -- rather than choose to switch to lower sulfur fuel. This may mean somewhat higher demand for high sulfur coal and more employment for miners in high sulfur coal areas -- and less demand for low sulfur coal and associated employment.

In addition to the nationwide employment impact of alternatives discussed above, it is important that your study determine what the real

national cost would be of each job that is created or retained in high sulfur areas (and lost or not created in low sulfur areas). It seems likely that the cost of each job created or retained would be very high, particularly when you take into account such relevant factors as:

- . the fact that the least cost alternative for reducing SO₂ (as proposed by President Bush) was not selected;
- . the costs of collecting the nationwide tax on electric customers;
- . the adverse economic effects on the individuals, organizations and regions from which taxes are collected;
- . the cost of administering the subsidy program;
- . the real possibility that the costs of installing scrubbers would be higher than necessary because costs are subsidized (i.e., less incentive for cost control); and
- . the costs incurred because job increases did not occur in low sulfur coal regions.

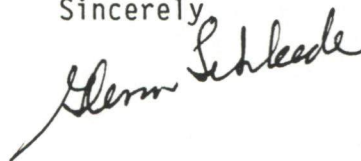
An objective assessment of the true national costs of a tax and subsidy program to protect high sulfur coal mining jobs and regions seems likely to suggest that other alternatives for dealing with potential job losses and economic dislocation should be considered.

Certainly, the approaches outlined in your letter of September 20, 1989 are logical alternatives, including placement assistance, training and/or relocation assistance to displaced workers, and discretionary assistance under the Job Training Partnership Act programs.

Hopefully, your study will consider the possibility for states to take actions to deal with adverse economic and job impacts of acid rain legislation.

Please let me know if there is additional information that might be useful in your study.

Sincerely,



Attachments

cc: The Honorable John H. Sununu
The Honorable William K. Reilly

1987 SULFUR DIOXIDE EMISSIONS, EMISSION RATES AND COAL CONSUMPTION BY STATE
 C\123/1987S02 Coal-fired powerplants of 50 megawatts or more

12:35 PM
 27-Mar-89

27-Mar-89	SO2 EMISSIONS			EMISSION RATES		COAL CONSUMPTION	
STATE	EMIS. RANK 1987	THOUSAND TONS	% OF U.S. TOTAL	LBS EMITTED PER MMBTU	THOUSAND TONS	% OF U.S. TOTAL	
OHIO	1	2,182.3	14.68%	3.88	47,304.7	6.61%	
INDIANA	2	1,314.0	8.84%	3.28	36,787.0	5.14%	
PENNSYLVANIA	3	1,197.6	8.06%	2.37	41,207.4	5.75%	
WEST VIRGINIA	4	925.4	6.23%	2.43	30,605.3	4.27%	
GEORGIA	5	908.3	6.11%	2.75	27,128.4	3.79%	
MISSOURI	6	879.2	5.92%	3.61	22,893.5	3.20%	
ILLINOIS	7	878.6	5.91%	2.87	28,760.1	4.02%	
TENNESSEE	8	818.2	5.50%	3.30	20,696.8	2.89%	
KENTUCKY	9	758.8	5.11%	2.30	28,536.0	3.98%	
ALABAMA	10	574.2	3.86%	2.26	20,744.8	2.90%	
TOP 10		10,436.6	70.22%		304,664.0	42.54%	
FLORIDA	11	525.9	3.54%	1.87	22,598.3	3.16%	
TEXAS	12	458.1	3.08%	0.81	78,802.1	11.00%	
MICHIGAN	13	427.7	2.88%	1.21	30,605.8	4.27%	
NORTH CAROLINA	14	312.2	2.10%	1.44	17,255.3	2.41%	
WISCONSIN	15	283.3	1.91%	1.68	17,498.0	2.44%	
MARYLAND	16	234.5	1.58%	2.25	8,227.8	1.15%	
NEW YORK	17	208.1	1.40%	2.08	7,827.7	1.09%	
IOWA	18	188.7	1.27%	1.60	12,924.9	1.80%	
SOUTH CAROLINA	19	166.9	1.12%	1.46	9,018.8	1.26%	
KANSAS	20	151.3	1.02%	1.16	14,925.5	2.08%	
SECOND 10		2,956.7	19.89%		219,684.2	30.68%	
TOP 20		13,393.3	90.11%		524,348.2	73.22%	
VIRGINIA	21	147.1	0.99%	1.38	8,297.3	1.16%	
MISSISSIPPI	22	114.6	0.77%	1.99	4,557.8	0.64%	
NORTH DAKOTA	23	110.1	0.74%	0.96	17,434.3	2.43%	
WYOMING	24	98.9	0.67%	0.51	22,047.8	3.08%	
MASSACHUSETTS	25	98.4	0.66%	1.76	4,267.0	0.60%	
OKLAHOMA	26	88.3	0.59%	0.78	12,860.5	1.80%	
ARIZONA	27	85.0	0.57%	0.63	12,706.3	1.77%	
MINNESOTA	28	75.8	0.51%	0.66	13,235.5	1.85%	
NEW JERSEY	29	75.3	0.51%	1.89	3,006.1	0.42%	
LOUISIANA	30	70.6	0.48%	0.86	10,028.7	1.40%	
COLORADO	31	70.4	0.47%	0.51	14,007.2	1.96%	
ARKANSAS	32	66.3	0.45%	0.65	11,763.8	1.64%	
WASHINGTON	33	66.0	0.44%	1.49	5,468.4	0.76%	
DELAWARE	34	55.9	0.38%	1.32	3,236.4	0.45%	
NEVADA	35	51.5	0.35%	0.68	6,806.7	0.95%	
NEW HAMPSHIRE	36	49.4	0.33%	3.17	1,163.2	0.16%	
NEW MEXICO	37	42.1	0.28%	0.32	14,316.1	2.00%	
NEBRASKA	38	39.6	0.27%	0.71	6,428.0	0.90%	
UTAH	39	27.2	0.18%	0.21	11,165.6	1.56%	
MONTANA	40	20.4	0.14%	0.32	7,529.7	1.05%	
SOUTH DAKOTA	41	9.1	0.06%	2.15	698.4	0.10%	
CONNECTICUT	42	7.5	0.05%	0.73	786.9	0.11%	
REMAINING 22		1,469.8	9.89%		191,811.8	26.78%	
TOTAL		14,863.1	100.00%		716,160.2	100.00%	

There were no coal-fired powerplants of 50 MW or more burning coal in eight states during 1987: Alaska, California, Hawaii, Idaho, Maine, Oregon, Rhode Island and Vermont

TABLE 1-2

c:/123/sumso2.wk1			1987				CUMULATIVE DATA STARTING WITH LARGEST SO2 EMITTERS -1987					
29-Mar-89 02:06 PM												
1987 SO2 EMIS. RANK	UTILITY	ST.	TO- NAMEPLATE TAL CAPACITY PLA- MW NTS (000'S)	TONS COAL (000'S)	TONS SO2 EMIT. (000'S)	PERCENT OF U.S. TOTAL	CUMULATIVE CAPACITY MW (000'S)	% OF U.S. TOTAL	CUMULATIVE COAL CONSUMPTION TONS (000'S)	% OF U.S. TOTAL	CUMULATIVE SO2 EMITTED TONS (000'S)	% OF U.S. TOTAL
1.0	SOUTHERN COMPANY, THE											
1.1	GEORGIA POWER CO	GA.	9 13,187	26,336.6	895.00	6.025%						
1.2	ALABAMA POWER CO	AL.	6 7,387	13,634.6	345.52	2.326%						
1.3	GULF POWER COMPANY	FL.	3 1,573	369.4	203.51	1.370%						
1.4	MISSISSIPPI POWER CO	MS.	2 1,750	3,834.2	112.69	0.759%						
			23,897	44,174.8	1556.72	10.479%	23,897	7.640%	44,174.8	6.204%	1556.72	10.479%
2.0	AMERICAN ELECTRIC POWER CO., INC.*											
2.1	OHIO POWER CO	OH/WV	4 6,475	13,374.5	906.90	6.105%						
2.2	CARDINAL OPERATING CO	OH.	1 1,880	3,953.1	170.36	1.147%						
2.3	APPALACHIAN POWER CO	V/WV	5 5,722	10,398.9	150.96	1.016%						
2.4	COLUMBUS & S OH ELEC CO	OH.	3 2,513	3,253.0	128.64	0.866%						
2.5	IND & MICH ELECTRIC CO	IN.	3 2,896	4,767.1	117.90	0.794%						
2.6	KENTUCKY POWER CO	KY.	1 1,097	2,005.4	45.36	0.305%						
2.7	CENTRAL OPERATING CO	WV.	1 1,106	1,455.3	30.37	0.204%						
			21,689	39,207.3	1550.48	10.436%	45,586	14.573%	83,382.1	11.710%	3107.20	20.915%
3.0	TENNESSEE VALLEY AUTH	KY/TN/AL	11 17,486	33,557.3	1286.04	8.657%	63,072	20.163%	116,739.4	16.423%	4393.24	29.572%
4.0	ALLEGHENY POWER SYSTEM, INC.											
4.1	MONONGAHELA POWER CO	WV.	6 5,173	11,996.6	410.24	2.762%						
4.2	WEST PENN POWER CO	PA.	3 2,354	4,949.3	201.12	1.354%						
4.3	POTOMAC EDISON CO (THE)	MD.	1 110	235.4	4.54	0.031%						
			7,637	17,181.3	615.91	4.146%	70,709	22.604%	134,120.7	18.836%	5009.15	33.718%
5.0	GENERAL PUBLIC UTILITIES CORP.											
5.1	PENNSYLVANIA ELEC CO	PA.	7 6,803	15,296.4	534.26	3.596%						
5.2	METROPOLITAN EDISON CO	PA.	2 652	1,250.4	42.98	0.289%						
			7,455	16,546.8	577.23	3.886%	78,164	24.988%	150,667.5	21.160%	5586.38	37.504%

*Some plants listed under American Electric Power are not fully owned by AEP (e.g., Cardinal, Connesville). Also, AEP's list does not include its interest in plants operated by others (e.g., WC Beckjord, operated by Cincinnati G&E; JM Stuart, operated by Daytona P&L; and Kyger Creek, operated by Ohio Valley Electric Company -- which is 42% owned by AEP and subsidiaries.)

TABLE 1-2

c:/123/sumso2.wk1			1987				CUMULATIVE DATA STARTING WITH LARGEST SO2 EMMITTERS -1987							
1987	29-Mar-89													
SO2	02:06 PM													
EMIS.														
RANK														
	UTILITY	ST.	TO- NAMEPLATE	TONS	TONS	PERCENT	CUMULATIVE		CUMULATIVE		CUMULATIVE			
			TAL CAPACITY	SO2	SO2	OF U.S.	CAPACITY		COAL CONSUMPTION		SO2 EMMITTED			
			PLA- MW	COAL	EMIT.	TOTAL	MW	% OF U.S.	TONS	% OF U.S.	TONS	% OF U.S.		
			NTS (000'S)	(000'S)	(000'S)		(000'S)	TOTAL	(000'S)	TOTAL	(000'S)	TOTAL		
6.0	OHIO VALLEY ELECTRIC CORP.													
6.1	INDIANA-KETUCKY ELEC CORP	IN.	1	1,304	4,216.9	271.36								
6.2	OHIO VALLEY ELEC CORP	OH.	1	1,086	3,063.3	212.06								
				2,390	7,280.2	483.41	3.254%	80,553	25.752%	157,947.7	22.182%	6069.80	40.858%	
7.0	PUBLIC SERV CO OF IND INC	IN.	6	6,184	11,252.7	475.15	3.198%	86,737	27.729%	169,200.4	23.763%	6544.95	44.056%	
8.0	UNION ELECTRIC CO	MO.	4	5,746	10,245.5	383.21	2.580%	92,483	29.566%	179,445.9	25.201%	6928.16	46.636%	
9.0	OHIO EDISON CO.													
9.0	OHIO EDISON CO	OH.	6	3,523	7,711.4	307.29	2.068%							
9.1	PENNSYLVANIA POWER CO	PA.	2	2,930	6,392.7	56.24	0.379%							
				6,453	14,104.1	363.53	2.447%	98,936	31.628%	193,550.0	27.182%	7291.69	49.083%	
10.0	ILLINOIS POWER CO	IL.	5	3,370	7,349.2	340.56	2.292%	102,306	32.706%	200,899.2	28.214%	7632.25	51.376%	
11.0	CENTERIOR ENERGY CORP.													
11.1	CLEVELAND ELEC ILLUM CO	OH.	4	3,038	5,334.5	278.69	1.876%							
11.2	TOLEDO EDISON CO (THE)	OH.	2	947	1,516.7	35.47	0.239%							
				3,985	6,851.2	314.16	2.115%	106,291	33.980%	207,750.4	29.176%	7946.40	53.490%	
12.0	PENNSYLVANIA PWR & LGT CO	PA.	5	3,980	9,635.3	311.54	2.097%	110,271	35.252%	217,385.7	30.530%	8257.95	55.587%	
13.0	ASSOCIATED ELEC COOP	MO.	2	2,335	4,985.2	259.66	1.748%	112,606	35.999%	222,370.9	31.230%	8517.61	57.335%	

TABLE 1-2

c:/123/sumso2.wk1
29-Mar-89
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1987 SO2 EMIS. RANK	UTILITY	ST.	1987					CUMULATIVE DATA STARTING WITH LARGEST SO2 EMITTERS - 1987					
			TO- NAMEPLATE	TAL CAPACITY	TONS	SO2	PERCENT	CUMULATIVE	CUMULATIVE	CUMULATIVE			
			PLA- MW	COAL	EMIT.	OF U.S.	TOTAL	MM	% OF U.S.	TONS	% OF U.S.	TONS	% OF U.S.
			NTS (000'S)	(000'S)	(000'S)			(000'S)	TOTAL	(000'S)	TOTAL	(000'S)	TOTAL
14.0	DETROIT EDISON CO (THE)	MI.	8	8,239	20,151.0	258.05	1.737%	120,845	38.632%	1242,521.9	34.060%	8775.66	59.072%
15.0	VIRGINIA ELEC & POWER CO	VA/WV	6	4,647	9,958.7	249.89	1.682%	125,492	40.118%	1252,460.6	35.458%	9025.55	60.754%
16.0	TEXAS UTILITIES ELEC CO	TX.	4	6,135	31,917.0	227.64	1.532%	131,627	42.079%	1284,397.6	39.941%	9253.18	62.287%
17.0	CENTRAL ILL PUBLIC SER CO	IL.	5	2,903	4,460.1	210.20	1.415%	134,530	43.007%	1288,857.7	40.567%	9463.39	63.702%
18.0	DAYTON PWR & LGT CO (THE)	OH.	3	3,521	8,339.6	204.92	1.375%	138,051	44.133%	1297,197.3	41.738%	9668.30	65.081%
19.0	TAMPA ELECTRIC CO	FL.	2	3,093	6,903.8	192.99	1.299%	141,144	45.122%	1304,101.1	42.708%	9861.30	66.380%
20.0	COMMONWEALTH EDISON CO.												
20.1	COMMONWEALTH EDISON CO	IL.	7	7,829	11,267.5	180.80	1.217%						
20.2	COMMONWEALTH ED CO IND	IN.	1	614	1,024.9	6.46	0.043%						
				8,443	12,292.4	187.25	1.260%	149,587	47.821%	1316,393.5	44.434%	10048.55	67.641%
21.0	POTOMAC ELECTRIC PWR CO	VA/MD	4	3,082	6,128.0	184.53	1.242%	152,669	48.806%	1322,521.5	45.295%	10233.08	68.867%
22.0	NORTHERN IND PUB SERV CO	IN.	4	3,769	4,840.1	177.03	1.192%	156,438	50.011%	1327,361.6	45.975%	10410.12	70.075%
23.0	KENTUCKY UTILITIES CO	KY.	4	3,304	5,627.7	176.94	1.191%	159,742	51.067%	1332,989.3	46.765%	10587.05	71.266%
24.0	DUKE POWER CO	NC/SC	8	7,573	8,782.5	161.76	1.089%	167,315	53.488%	1341,771.8	47.998%	10748.61	72.755%
25.0	CAROLINA POWER & LIGHT CO	NC/SC	8	5,545	8,913.7	160.39	1.080%	172,860	55.261%	1350,685.5	49.250%	10909.20	73.474%
26.0	KANSAS CITY PWR & LGT CO	KS/MO	4	3,382	8,512.5	159.47	1.073%	176,242	56.342%	1359,198.0	50.446%	11068.68	74.508%
27.0	CINCINNATI GAS ELEC CO	OH/KY	3	3,269	6,072.6	151.41	1.019%	179,511	57.387%	1365,270.6	51.299%	11220.08	75.527%
28.0	BIG RIVERS ELECTRIC CORP	KY.	4	1,995	4,948.3	145.63	0.980%	181,506	58.025%	1370,218.9	51.994%	11365.71	76.507%
29.0	PACIFIC POWER & LIGHT CO	WA/WY	4	4,446	18,102.8	143.70	0.967%	185,952	59.446%	1368,321.7	54.536%	11509.41	77.475%

TABLE 1-2

c:/123/sumso2.wk1			1987					CUMULATIVE DATA STARTING WITH LARGEST SO2 EMITTERS -1987				
29-Mar-89 02:06 PM												
1987 SO2 EMIS. RANK	UTILITY	ST.	TO- NAMEPLATE TAL CAPACITY PLA- MW NTS (000'S)	TONS COAL (000'S)	TONS SO2 EMIT. (000'S)	PERCENT OF U.S. TOTAL	CUMULATIVE CAPACITY MW (000'S)	% OF U.S. TOTAL	CUMULATIVE COAL CONSUMPTION TONS (000'S)	% OF U.S. TOTAL	CUMULATIVE SO2 EMMITTED TONS (000'S)	% OF U.S. TOTAL
30.0	INDIANAPOLIS PWR & LGT CO	IN.	3 2,871	5,764.3	133.87	0.901%	188.823	60.364%	374,086.0	55.345%	11643.28	78.376%
31.0	CONSUMERS POWER CO	MI.	5 3,098	7,120.0	126.75	0.853%	191.921	61.354%	401,206.0	56.345%	11770.03	79.225%
32.0	SOUTH CAROLINA ELEC & GAS CO	SC.	5 2,438	4,580.9	112.18	0.755%	194.359	62.134%	405,786.9	56.989%	11882.21	79.984%
33.0	WISCONSIN ELECTRIC PWR CO	WI.	4 3,597	7,043.5	107.39	0.723%	197.956	63.284%	412,830.4	57.978%	11969.60	80.707%
34.0	NIAGARA MOHAWK POWER CORP	NY.	2 1,456	2,799.5	101.01	0.680%	199.412	63.749%	415,629.9	58.371%	12090.61	81.367%
35.0	WISCONSIN PWR & LGT CO	WI.	4 2,198	6,158.2	94.06	0.633%	201.610	64.452%	421,788.1	59.236%	12184.67	82.020%
36.0	FLORIDA POWER CORPORATION	FL.	1 2,443	5,721.2	92.60	0.623%	204.053	65.233%	427,509.3	60.039%	12277.27	82.643%
37.0	CENTRAL & SOUTH WEST CORP.											
37.1	SOUTHWESTERN ELEC PWR CO	TX/AR	3 2,951	9,283.4	50.04	0.337%						
37.2	PUBLIC SERVICE CO OF OKLA	OK.	1 945	2,838.8	21.76	0.144%						
37.3	CENTRAL POWER & LIGHT CO	TX.	1 600	1,908.7	13.77	0.093%						
37.4	WEST TEXAS UTILITIES CO	TX.	1 664	1,711.3	3.14	0.021%						
			5,160	15,742.2	88.32	0.595%	209.214	66.882%	443,251.5	62.250%	12365.59	83.236%
38.0	NEW ENGLAND ELEC SYSTEM	MA.	2 1,455	3,324.9	74.83	0.504%	210.669	67.348%	446,576.4	62.717%	12440.42	83.742%
39.0	SOUTHERN INDIANA G & E CO	IN.	2 1,268	2,182.5	73.79	0.497%	211.937	67.753%	448,758.9	63.024%	12514.21	84.238%
40.0	ELECTRIC ENERGY INC	IL.	1 1,100	1,937.4	72.54	0.488%	213.037	68.105%	450,696.3	63.296%	12586.75	84.726%
41.0	EMPIRE DISTRICT ELEC CO	KS/MO	2 323	807.4	72.19	0.486%	213.360	68.208%	451,503.7	63.409%	12658.94	85.212%
42.0	N Y STATE ELEC & GAS CORP	NY.	6 1,429	3,732.7	70.40	0.474%	214.789	68.665%	455,236.4	63.933%	12729.34	85.686%
43.0	SALT RIVER PROJECT	AZ.	2 3,231	8,462.2	70.02	0.471%	218.020	69.696%	463,698.6	65.122%	12799.36	86.157%

TABLE 1-2

c:/123/sumso2.wk1			1987				CUMULATIVE DATA STARTING WITH LARGEST SO2 EMITTERS -1987							
29-Mar-89 02:06 PM														
1987 SO2 EMIS. RANK	UTILITY	ST.	TO- NAMEPLATE TAL CAPACITY PLA- MW NTS (000'S)	TONS COAL (000'S)	TONS SO2 EMIT. (000'S)	PERCENT OF U.S. TOTAL	CUMULATIVE CAPACITY MW (000'S)	% OF U.S. TOTAL	CUMULATIVE COAL CONSUMPTION TONS (000'S)	% OF U.S. TOTAL	CUMULATIVE SO2 EMITTED TONS (000'S)	% OF U.S. TOTAL		
44.0	SPRINGFIELD (CITY OF)	IL/MD	4	909	1,576.3	64.03	0.431%	218,929	69.988%	465,274.9	65.343%	12863.38	86.588%	
45.0	HOUSTON LIGHTING & PWR CO	TX.	2	4,324	15,631.1	60.42	0.407%	223,253	71.371%	480,906.0	67.538%	12923.80	86.995%	
46.0	BALTIMORE GAS & ELEC CO	MD.	3	1,444	2,683.9	57.71	0.388%	224,697	71.832%	463,589.9	67.915%	12981.51	87.384%	
47.0	MID SOUTH/ARKANSAS PWR & LT AR.	AR.	2	3,200	10,014.6	56.20	0.378%	227,897	72.855%	493,604.5	69.322%	13037.71	87.762%	
48.0	EAST KY RURAL ELEC COOP	KY.	3	1,310	3,039.9	54.99	0.370%	229,207	73.274%	496,644.4	69.749%	13092.71	88.132%	
49.0	PUB SERV CO OF NEW HAMP	NH.	2	609	1,163.2	49.42	0.333%	229,816	73.469%	497,807.6	69.912%	13142.12	88.465%	
50.0	DELMARVA POWER & LIGHT CO	DE.	2	959	2,449.5	48.37	0.326%	230,775	73.776%	500,257.1	70.256%	13190.49	88.790%	
51.0	HOOSIER ENERGY RURAL	IN.	2	1,213	2,509.7	47.42	0.319%	231,988	74.163%	502,766.8	70.609%	13237.92	89.110%	
52.0	SOUTHWESTERN PUB SERV CO	TX.	2	2,216	7,202.2	46.63	0.314%	234,204	74.871%	509,969.0	71.620%	13284.55	89.424%	
53.0	OKLAHOMA GAS & ELEC CO	OK.	2	2,855	6,345.8	45.85	0.309%	237,059	75.784%	516,314.8	72.511%	13330.40	89.732%	
54.0	DUQUESNE LGT CO	PA.	3	1,486	2,245.2	45.71	0.308%	238,545	76.259%	518,560.0	72.827%	13376.11	90.040%	
55.0	SO CAROLINA PUB SERV AUTH	SC.	4	2,325	3,997.0	44.81	0.302%	240,870	77.003%	522,557.0	73.388%	13420.92	90.341%	
56.0	SOUTHERN CALIF EDISON CO	NV.	1	1,636	4,266.6	44.10	0.297%	242,506	77.526%	526,823.6	73.987%	13465.01	90.638%	
57.0	WISCONSIN PUB SERV CORP	WI.	2	829	2,072.5	43.21	0.291%	243,335	77.791%	528,896.1	74.278%	13508.22	90.929%	
58.0	UTILICORP UNITED INC	MO.	1	524	711.0	43.12	0.290%	243,859	77.958%	529,607.2	74.378%	13551.34	91.220%	
59.0	INTERSTATE POWER CO	IA/MN	4	739	1,390.4	43.02	0.290%	244,598	78.194%	530,997.6	74.573%	13594.36	91.509%	
60.0	ARIZONA PUBLIC SERVICE CO	AZ/NM	2	3,362	11,371.8	42.47	0.286%	247,960	79.269%	542,369.4	76.170%	13636.83	91.795%	
61.0	NORTHERN STATES POWER CO	MN.	5	3,264	9,525.9	42.45	0.286%	251,224	80.312%	551,895.3	77.508%	13679.29	92.081%	
62.0	PUBLIC SERVICE CO OF COLO	CO.	6	2,374	6,166.2	40.32	0.271%	253,598	81.071%	558,061.5	78.374%	13719.61	92.352%	
63.0	BASIN ELEC POWER COOP	ND/WY	3	3,242	13,776.6	39.48	0.266%	256,840	82.108%	571,838.1	80.309%	13759.09	92.618%	

TABLE 1-2

c:/123/sumso2.wk1			1987				CUMULATIVE DATA STARTING WITH LARGEST SO2 EMMITTERS -1987						
29-Mar-89 02:06 PM													
1987 SO2 EMIS. RANK	UTILITY	ST.	TO- NAMEPLATE TAL CAPACITY PLA- MW NTS (000'S)	TONS COAL (000'S)	TONS SO2 EMIT. (000'S)	PERCENT OF U.S. TOTAL	CUMULATIVE CAPACITY MW (000'S)	% OF U.S. TOTAL	CUMULATIVE COAL CONSUMPTION TONS (000'S)	% OF U.S. TOTAL	CUMULATIVE SO2 EMMITTED TONS (000'S)	% OF U.S. TOTAL	
64.0	ATLANTIC CITY ELECTRIC												
64.0	ATLANTIC CITY ELEC CO	NJ.	1	299	636.4	33.13	0.223%						
64.1	DEEPWATER OPERATING CO	NJ.	1	121	415.0	6.31	0.042%						
				420	1051.4	39.44	0.265%	257,260	82.242%	572,889.5	80.457%	13798.53	92.683%
65.0	UTAH POWER & LIGHT CO	UT/WY	5	3,310	8,464.3	37.86	0.255%	260,570	83.300%	581,353.8	81.645%	13836.40	93.136%
66.0	OWENSBORO (CITY OF)	KY.	1	416	648.6	37.44	0.252%	260,986	83.433%	582,002.3	81.736%	13873.83	93.390%
67.0	LOUISVILLE GAS & ELEC CO	KY.	2	2,361	4,001.9	36.17	0.243%	263,347	84.188%	586,004.2	82.298%	13910.00	93.633%
68.0	PUBLIC SERV ELEC & GAS CO	NJ.	2	1,313	1,954.7	35.85	0.241%	264,660	84.608%	587,958.9	82.573%	13945.85	93.875%
69.0	DAIRYLAND POWER COOP	WI.	3	973	2,053.6	34.64	0.233%	265,633	84.919%	590,012.5	82.861%	13980.49	94.108%
70.0	CAJUN ELEC POWER COOP INC	LA.	1	1,678	3,939.3	33.09	0.223%	267,311	85.455%	593,951.8	83.415%	14013.58	94.331%
71.0	CENTRAL ILLINOIS LIGHT CO	IL.	2	1,221	2,254.5	32.72	0.220%	268,532	85.846%	596,206.3	83.731%	14046.30	94.551%
72.0	IOWA SOUTHERN UTILS CO	IA.	2	938	2,596.9	31.43	0.212%	269,470	86.145%	598,803.2	84.096%	14077.73	94.762%
73.0	IOWA ELEC LGT & PWR CO	IA.	3	487	719.4	31.02	0.209%	269,957	86.301%	599,522.6	84.197%	14108.75	94.971%
75.0	LOWER COLORADO RIVER AUTH	TX.	1	1,230	4,139.7	28.25	0.190%	271,187	86.694%	603,662.3	84.778%	14137.00	95.161%
74.0	COOPERATIVE POWER ASSO	ND.	1	1,012	4,390.5	28.28	0.190%	272,199	87.018%	608,052.9	85.395%	14165.27	95.352%
76.0	ROCHESTER GAS & ELEC CORP	NY	2	335	620.2	27.24	0.183%	272,534	87.125%	608,673.1	85.482%	14192.51	95.535%
77.0	KANSAS POWER & LIGHT CO	KS.	3	2,957	8,793.3	27.23	0.183%	275,491	88.070%	617,466.4	86.717%	14219.74	95.718%
78.0	MINNESOTA POWER & LGT CO	MN.	2	1,189	3,450.1	25.84	0.174%	276,680	88.450%	620,916.5	87.202%	14245.58	95.892%
79.0	IOWA PUBLIC SERVICE CO	IA.	1	1,686	2,829.3	25.75	0.173%	278,366	88.989%	623,745.7	87.599%	14271.33	96.066%
80.0	MINNKOTA POWER COOP INC	ND.	1	734	3,520.8	25.70	0.173%	279,100	89.224%	627,266.6	88.093%	14297.02	96.239%

TABLE 1-2

c:/123/sumso2.wk1			1987				CUMULATIVE DATA STARTING WITH LARGEST SO2 EMITTERS -1987						
29-Mar-89 02:06 PM													
1987			TO- NAMEPLATE		TONS		CUMULATIVE		CUMULATIVE		CUMULATIVE		
SO2			TAL CAPACITY		SO2		CAPACITY		COAL CONSUMPTION		SO2 EMITTED		
EMIS.			PLA- MW	COAL	EMIT.	OF U.S.	MW	% OF U.S.	TONS	% OF U.S.	TONS	% OF U.S.	
RANK	UTILITY	ST.	NTS (000'S)	(000'S)	(000'S)	TOTAL	(000'S)	TOTAL	(000'S)	TOTAL	(000'S)	TOTAL	
81.0	KANSAS CITY (CITY OF)	KS.	3	624	1,318.1	25.04	0.169%	279,724	89.424%	628,584.7	88.278%	14322.06	96.407%
82.0	SEMINOLE ELECTRIC COOP	FL.	1	1,240	3,110.5	24.29	0.163%	280,964	89.620%	631,695.2	88.715%	14346.35	96.571%
83.0	CENTRAL LOUISIANA ELEC CO	LA.	2	1278	4,195.6	22.25	0.150%	282,242	90.228%	635,890.8	89.305%	14368.60	96.720%
84.0	IOWA ILLINOIS GAS & ELEC	IA.	2	920	2,223.3	20.86	0.140%	283,162	90.523%	638,114.1	89.617%	14389.45	96.861%
85.0	NEBRASKA PUB POWER DIST	NE.	3	1,676	3,061.4	19.70	0.133%	284,838	91.058%	641,175.5	90.047%	14409.15	96.993%
86.0	COLORADO-UTE ELEC ASSN	CO.	2	1,804	5,319.2	18.95	0.128%	286,642	91.635%	646,494.7	90.794%	14428.10	97.121%
87.0	MONTANA POWER CO (THE)	MT.	2	2,463	7,309.9	18.48	0.124%	289,105	92.422%	653,804.6	91.820%	14446.58	97.245%
88.0	LANSING (CITY OF)	MI.	3	615	1,139.1	18.08	0.122%	289,720	92.619%	654,943.7	91.980%	14464.65	97.367%
89.0	SAN ANTONIO PUB SERV BRD	TX.	1	892	2,745.4	17.30	0.116%	290,612	92.904%	657,689.1	92.366%	14481.95	97.483%
90.0	OMAHA PUBLIC POWER DIST	NE.	2	1,261	2,928.7	16.60	0.112%	291,873	93.307%	660,617.8	92.777%	14498.55	97.595%
91.0	SOUTHERN ILL PWR COOP	IL.	1	310	656.4	16.29	0.110%	292,183	93.406%	661,274.3	92.869%	14514.84	97.705%
92.0	UPPER PENINSULA GEN CO	MI.	1	625	1,455.9	16.07	0.108%	292,807	93.606%	662,730.1	93.074%	14530.91	97.813%
93.0	MONTANA DAKOTA UTILS CO	ND/MT	3	600	2,234.0	15.46	0.104%	293,407	93.798%	664,964.1	93.386%	14546.37	97.917%
94.0	IOWA POWER & LIGHT CO	IA.	1	856	2,356.5	15.26	0.103%	294,264	94.072%	667,320.6	93.719%	14561.62	98.020%
95.0	GULF STATES UTILITIES CO	LA.	1	615	1,893.8	15.25	0.103%	294,879	94.268%	669,214.4	93.985%	14576.87	98.122%
96.0	ALABAMA ELEC. COOP INC.	AL.	1	536	1,110.5	14.19	0.096%	295,415	94.440%	670,324.9	94.140%	14591.06	98.216%
97.0	SAVANNAH ELEC & PWR CO	GA.	2	378	791.7	13.34	0.090%	295,793	94.561%	671,116.6	94.252%	14604.40	98.308%
98.0	GRAND RIVER DAM AUTHORITY	OK.	1	1,010	2,752.9	13.28	0.089%	296,803	94.883%	673,869.6	94.638%	14617.68	98.398%
99.0	SAN MIGUEL ELEC COOP INC	TX.	1	448	2,694.6	12.68	0.085%	297,251	95.027%	676,564.2	95.017%	14630.35	98.483%

TABLE 1-2

c:/123/sumso2.wk1			1987					CUMULATIVE DATA STARTING WITH LARGEST SO2 EMMITTERS -1987					
29-Mar-89 02:06 PM			TO- NAMEPLATE		TONS		CUMULATIVE		CUMULATIVE		CUMULATIVE		
1987			TAL CAPACITY	TONS	SO2	PERCENT	CAPACITY		COAL CONSUMPTION		SO2 EMITTED		
SO2			PLA- MW	COAL	EMIT.	OF U.S.	MW	% OF U.S.	TONS	% OF U.S.	TONS	% OF U.S.	
EMIS.			NTS (000'S)	(000'S)	(000'S)	TOTAL	(000'S)	TOTAL	(000'S)	TOTAL	(000'S)	TOTAL	
RANK	UTILITY	ST.											
100.0	MUSCATINE (CITY OF)	IA.	1	249	523.3	12.33	0.083%	297,499	95.106%	677,087.6	95.090%	14642.68	98.566%
101.0	EUA/MONTAUP ELECTRIC CO.	MA.	1	174	528.4	12.06	0.081%	297,673	95.162%	677,616.0	95.164%	14654.74	98.647%
102.0	NORTHEAST/HOLYOKE WTR PW CO	MA.	1	136	413.6	11.53	0.078%	297,809	95.205%	678,029.6	95.223%	14666.27	98.725%
103.0	RICHMOND (CITY OF)	IN.	1	93	228.8	11.02	0.074%	297,902	95.235%	678,258.4	95.255%	14677.29	98.799%
104.0	OTTER TAIL POWER CO	MN/SD	2	593	758.7	10.01	0.067%	298,495	95.424%	679,017.1	95.361%	14687.30	98.866%
105.0	COLORADO SPRINGS(CITY OF)	CO.	2	464	1,416.0	10.10	0.068%	298,959	95.573%	680,433.1	95.560%	14697.40	98.934%
106.0	UNITED POWER ASSN	ND.	1	172	944.8	9.03	0.061%	299,131	95.628%	681,377.9	95.693%	14706.43	98.995%
107.0	ESTRN IOWA LGT& PWR COOP	IA.	1	63	165.8	8.93	0.060%	299,194	95.648%	681,543.7	95.716%	14715.36	99.055%
108.0	TEXAS MUN POWER AGENCY	TX.	1	408	3,317.9	8.36	0.056%	299,602	95.778%	684,861.6	96.182%	14723.72	99.111%
109.0	GAINESVILLE (CITY OF)	FL.	1	251	526.6	8.11	0.055%	299,852	95.858%	685,388.2	96.256%	14731.83	99.166%
110.0	PUB SERV CO OF NEW MEXICO	NM.	1	1,779	5,151.9	7.84	0.053%	301,631	96.427%	690,540.1	96.979%	14739.66	99.219%
111.0	WESTERN FARMERS ELEC COOP	OK.	1	400	923.0	7.80	0.052%	302,031	96.555%	691,463.1	97.109%	14747.46	99.271%
112.0	UNITED ILLUMINATING CO	CT.	1	400	786.9	7.52	0.051%	302,431	96.683%	692,250.0	97.220%	14754.98	99.322%
113.0	ORRVILLE (CITY OF)	OH.	1	97	109.3	7.42	0.050%	302,528	96.714%	692,359.3	97.235%	14762.40	99.372%
114.0	INDEPENDENCE (CITY OF)	MO.	1	102	103.1	6.73	0.045%	302,630	96.746%	692,462.4	97.249%	14769.13	99.417%
115.0	SIERRA PACIFIC POWER CO	NV.	1	521	1,134.5	5.53	0.037%	303,151	96.913%	693,596.9	97.409%	14774.66	99.454%
116.0	ST JOSEPH LGT & PWR CO	MO.	1	115	69.1	4.81	0.032%	303,266	96.950%	693,666.0	97.418%	14779.47	99.487%
117.0	CENTRAL ELEC PWR COOP	MO.	1	59	83.5	4.79	0.032%	303,325	96.968%	693,749.5	97.430%	14784.26	99.519%
118.0	SIKESTON (CITY OF)	MO.	1	235	534.1	4.62	0.031%	303,560	97.044%	694,283.6	97.505%	14788.89	99.550%

TABLE 1-2

c:/123/sumso2.wk1			1987					CUMULATIVE DATA STARTING WITH LARGEST SO2 EMITTERS -1987					
29-Mar-89 02:06 PM			TO- NAMEPLATE		TONS		CUMULATIVE		CUMULATIVE		CUMULATIVE		
1987			TAL CAPACITY	TONS	SO2	PERCENT	CAPACITY		COAL CONSUMPTION		SO2 EMITTED		
SO2			PLA- MW	COAL	EMIT.	OF U.S.	MW	% OF U.S.	TONS	% OF U.S.	TONS	% OF U.S.	
EMIS.	UTILITY	ST.	NTS (000'S)	(000'S)	(000'S)	TOTAL	(000'S)	TOTAL	(000'S)	TOTAL	(000'S)	TOTAL	
RANK													
119.0	CENTRAL HUDSON GAS & ELEC	NY.	1	386	414.9	4.61	0.031%	303,946	97.167%	694,698.5	97.564%	14793.50	99.581%
120.0	LOS ANGELES (CITY OF)	UT.	1	1,640	3,993.0	4.36	0.029%	305,586	97.691%	698,691.5	98.124%	14797.86	99.610%
121.0	ALAMITO COMPANY	AZ.	1	350	1,029.7	4.16	0.028%	305,936	97.803%	699,721.2	98.269%	14802.02	99.638%
122.0	ROCHESTER (CITY OF)	MN.	1	99	120.4	4.04	0.027%	306,035	97.835%	699,841.5	98.286%	14806.06	99.666%
123.0	PAINESVILLE (CITY OF)	OH.	1	58	85.6	3.89	0.026%	306,093	97.853%	699,927.1	98.298%	14809.95	99.692%
124.0	LAKELAND (CITY OF)	FL.	1	334	753.2	3.46	0.023%	306,427	97.960%	700,680.3	98.404%	14813.41	99.715%
125.0	JAMESTOWN (CITY OF)	NY.	1	58	117.9	3.36	0.023%	306,484	97.979%	700,798.3	98.420%	14816.76	99.738%
126.0	PHILADELPHIA ELEC CO	PA.	2	895	1,245.8	3.04	0.020%	307,379	98.265%	702,044.1	98.595%	14819.80	99.755%
127.0	GRAND HAVEN (CITY OF)	MI.	1	85	189.3	2.96	0.020%	307,464	98.292%	702,233.4	98.622%	14822.76	99.778%
128.0	UNITED GAS IMP CO (THE)	PA.	1	50	192.4	2.69	0.018%	307,514	98.308%	702,425.8	98.649%	14825.45	99.796%
129.0	HOLLAND (CITY OF)	MI.	1	63	164.3	2.69	0.018%	307,577	98.328%	702,590.1	98.672%	14826.15	99.814%
130.0	MADISON GAS & ELEC CO	WI.	1	88	85.5	2.65	0.018%	307,665	98.356%	702,675.6	98.684%	14830.80	99.832%
131.0	PLAINS EL GEN TRANS COOP	NM.	1	233	634.5	2.05	0.014%	307,898	98.431%	703,310.1	98.773%	14832.85	99.845%
132.0	SOUTH MISS ELEC PWR ASSOC	MS.	1	408	723.5	1.97	0.013%	308,306	98.561%	704,033.6	98.875%	14834.82	99.859%
133.0	NEVADA POWER CO	NV.	1	612	1,405.6	1.90	0.013%	308,918	98.757%	705,439.2	99.072%	14836.72	99.872%
134.0	CEDAR FALLS (CITY OF)	IA.	1	52	36.2	1.78	0.012%	308,970	98.773%	705,475.4	99.077%	14838.50	99.884%
135.0	ORANGE & ROCKLAND UTL INC	NY.	1	387	142.6	1.50	0.010%	309,357	98.897%	705,617.9	99.097%	14840.00	99.894%
136.0	WYANDOTTE (CITY OF)	MI.	1	66	98.3	1.40	0.009%	309,422	98.918%	705,716.2	99.111%	14841.40	99.904%
137.0	MANITOWOC (CITY OF)	WI.	1	79	84.8	1.36	0.009%	309,501	98.943%	705,801.0	99.123%	14842.76	99.917%
138.0	FREMONT (CITY OF)	NE.	1	129	136.5	1.33	0.009%	309,630	98.984%	705,937.5	99.142%	14844.09	99.922%

TABLE 1-2

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29-Mar-89 02:06 PM													
1987 SO2 EMIS. RANK	UTILITY	ST.	TO- NAMEPLATE TAL CAPACITY PLA- MW NTS (000'S)	TONS COAL (000'S)	TONS SO2 EMIT. (000'S)	PERCENT OF U.S. TOTAL		CUMULATIVE CAPACITY MW (000'S)	% OF U.S. TOTAL	CUMULATIVE COAL CONSUMPTION TONS (000'S)	% OF U.S. TOTAL	CUMULATIVE SO2 EMITTED TONS (000'S)	% OF U.S. TOTAL
139.0	HAMILTON (CITY OF)	OH.	1 88	101.3	1.26	0.009%		309,718	99.012%	706,038.8	99.156%	14845.35	99.930%
140.0	GRAND ISLAND (CITY OF)	NE.	1 110	184.0	1.19	0.008%		309,828	99.047%	706,222.8	99.182%	14846.54	99.938%
141.0	SUNFLOWER ELEC COOP	KS.	1 319	915.0	1.13	0.008%		310,148	99.150%	707,137.8	99.310%	14847.67	99.946%
142.0	PLATTE RIVER POWER AUTH	CO.	1 255	1,105.8	1.04	0.007%		310,403	99.231%	708,243.5	99.466%	14848.71	99.953%
143.0	ORLANDO (CITY OF)	FL.	1 425	469.3	0.89	0.006%		310,828	99.367%	708,712.8	99.532%	14849.60	99.959%
144.0	HENDERSON (CITY OF)	KY.	1 51	17.8	0.87	0.006%		310,879	99.383%	708,730.6	99.534%	14850.47	99.965%
145.0	MICHIGAN SO CENT PWR AGEN	MI.	1 55	141.4	0.86	0.006%		310,934	99.401%	708,872.0	99.554%	14851.33	99.970%
146.0	MARQUETTE (CITY OF)	MI.	1 77	146.6	0.84	0.006%		311,011	99.426%	709,018.6	99.575%	14852.16	99.976%
147.0	HASTINGS (CITY OF)	NE.	1 76	117.4	0.80	0.005%		311,087	99.450%	709,136.0	99.591%	14852.97	99.981%
148.0	COLUMBUS (CITY OF)	OH.	1 90	49.2	0.75	0.005%		311,177	99.479%	709,185.1	99.598%	14853.71	99.986%
149.0	AMES (CITY OF)	IA.	1 109	159.6	0.75	0.005%		311,286	99.514%	709,344.7	99.620%	14854.47	99.992%
150.0	ARIZONA ELEC PWR COOP INC	AZ.	1 390	372.3	0.54	0.004%		311,676	99.638%	709,717.0	99.673%	14855.01	99.995%
151.0	DESERET GEN & TRANS COOP	UT.	1 400	909.2	0.37	0.003%		312,076	99.766%	710,626.2	99.800%	14855.38	99.998%
152.0	CORN BELT POWER COOP	IA.	1 53	2.9	0.14	0.001%		312,129	99.783%	710,629.1	99.801%	14855.53	99.999%
153.0	JACKSONVILLE (CITY OF)	FL.	1 679	1,418.4	0.08	0.001%		312,808	100.000%	712,047.5	100.000%	14855.61	99.999%
			1409	312,808	712,047.5	14885.60	=====						

Source of data: National Coal Association's estimates of SO2 emissions from coal-fired powerplants, 1980-1987.



Energy Ventures Analysis, Inc.

MAIN OFFICE: 1901 N. MOORE STREET, SUITE 1200 ARLINGTON, VIRGINIA 22209-1751

BRANCH OFF: PENN CENTER WEST-ONE, SUITE 300 PITTSBURGH, PENNSYLVANIA 15276

TELE: (703) 276-8900

FAX: (703) 276-9541

TELE: (412) 787-8624

FAX: (412) 788-1914

IMPACT OF ACID RAIN LEGISLATION ON EMPLOYMENT IN THE COAL MINING INDUSTRY

SUMMARY

Employment in the coal mining industry will increase slightly (i.e., approximately 1300 jobs or 1% of current industry employment) as a result of acid rain legislation, although there will be offsetting changes among the various coal mining districts. This conclusion is the result of extensive site-specific study¹ of the impact of Acid Rain legislation on utilities compliance decisions and coal markets. This study analyzed the impacts of legislation similar to the 1989 Sikorski/Waxman proposal, which requires states to achieve a fossil fuel average of 1.2# SO₂/MMBtu through freedom of choice to meet required emission levels rather than mandated scrubbing.

In responding to this type of legislation, each coal burning utility will carefully evaluate the two major options available to meet the emission requirements and chose the most cost-effective approach. These two options are (1) technology controls (e.g. flue gas desulfurization scrubbing) which involves significant capital costs and (2) switching to coal supplies with a lower sulfur content², which results in higher fuel costs and may involve some capital costs depending on the specific site.

The latter option results in shifts in coal production to some districts, such as Central Appalachia and Powder River Basin which have very low sulfur coal. Whereas some high sulfur coal districts, such as the Illinois Basin and Southern Appalachia, would experience declines in production. For the total industry, the net increases in employment would more than offset the net decreases in other areas. The changes in employment are not exactly offsetting since the productivity (i.e., tons produced per manhour) varies among the various coal producing regions.

The increase in employment for the coal mining industry resulting from coal switching to achieve lower sulfur emissions in order to comply with a 1.2# SO₂/MMBtu freedom of choice bill is summarized in the attached table. This increase would be a distinct change from the recent trends in industry employment. Employment within the mining industry has declined on average 12,000 jobs per year over the last several years due to productivity improvements within the industry. In fact, over the last decade, industry employment has declined more than 100,000 jobs or 42% while production increased 250 million tons or 27%. Thus changes in industry productivity have had and will continue to have a greater impact on total employment within the coal mining industry than acid rain legislation.

SELECTION OF ACID RAIN SCENARIO

Over the last few years several proposals for the reduction of sulfur dioxide emissions have been debated in Congress. While a consensus

IMPACT ON EMPLOYMENT IN THE COAL MINING INDUSTRY FROM COAL SWITCHING AS A RESULT OF ACID RAIN LEGISLATION

	CHANGES DUE TO COAL SWITCHING FOR A 1.2# BILL			HISTORICAL CHANGES IN EMPLOYMENT	
	Coal Demand in year 2000 Base Case (MM Tons)	Potential Tonnage (Loss)/Gain from Coal Switching (MM Tons)	Change in Jobs from Coal Switching (No. of Jobs)	Changes Between 1984-1987 (No. of Jobs)	Changes Between 1978-1987 (No. of Jobs)
Coal Producing Region					
Northern Appalachia	140	(36.8)	(6,809)	(12,616)	(37,002)
Illinois Basin	150	(40.1)	(6,098)	(3,778)	(9,448)
Central Appalachia	180	38.3	14,899	(9,115)	(33,052)
Southern Appalachia	16.7	(8.2)	(1,957)	(2,088)	(4,421)
Western Interior	9.1	(2.5)	(554)	190	848
Powder River Basin	204	31.5	402	(915)	116
Southern Wyoming	23.9	7.4	773	(635)	(681)
Colorado/Utah	30.8	6.6	690	(1,069)	(2,635)
Other (includes Imports)	140.5	9.9	---	(4,655)	(14,955)
TOTAL	895	6.1	1,345	(34,681)	(101,230)

within Congress has not yet emerged, the differences between the various proposals have narrowed. This analysis assumed the following acid rain scenario, which closely resembles the 1989 Sikorski/Waxman proposal:

- each coal fired utility must achieve an annual system average emission rate of 1.2 lbs. SO₂ per MMBtu in each state,
- no interstate or intrautility trading of emission reduction credits,
- system emission limitations apply to non-NSPS³ stations only,
- freedom to select the lowest cost solution to comply with the legislative requirements, and;
- compliance will be achieved by the year 2000.

UTILITY COMPLIANCE DECISIONS

Using the scenario described above for acid rain legislation, the study reviewed the economic alternatives for over 190 utility coal fired stations on a site-specific basis. The study incorporated the insights from interviews with utilities representing nearly 60% of the generating capacity in the 31 eastern acid rain deposit region and accounting for slightly more than 80% of 1980 SO₂ emissions in the region. For each utility system, the lowest cost method of achieving the emission rate limitation across the system was determined. Most western utilities and NSPS³ stations were not part of this study since they are already in compliance with the proposed emission rate limitation.

The two major options available to utilities are either retrofitting FGD scrubbers and continuing to use existing high sulfur coal supplies or switching to one of several alternative supplies of lower sulfur coal. While economic trade-offs were the primary focus of the study, site specific factors, such as the following, were important in driving utility compliance decisions:

- Boiler limitations: Some existing boilers can not burn certain types of coal. For example, cyclone boilers can not burn most Eastern low sulfur high fusion coals and thus their switching options were limited to western low sulfur low fusion coals.
- Site constraints: Physical constraints at several utility stations made installation of FGD scrubbers prohibitively expensive.
- Location: The location of the utility station greatly influenced the transportation costs of the alternative sources of coal. The study analyzed several alternative sources of coal and transportation costs for each coal fired station.

The ultimate decision by a utility to switch or retrofit technology controls is sensitive to changes in low sulfur coal (including compliance coal) prices. The study examined the demand for these lower sulfur

coals at a range of prices and the ability of low sulfur coal producers to meet increase demand at different costs. From this analysis, the study determined the anticipated changes in eastern low sulfur coal prices and the likely compliance decisions at these prices.

In particular, compliance coal (i.e., less than approximately 0.75% sulfur) demand generated by acid rain legislation is very sensitive to eastern compliance coal prices. Based upon this demand curve, EVA estimated the likely compliance coal price would rise from \$32-\$34 to \$38-\$40/ton (FOB mine in the year 2000 in \$ 1988). This price increase would be sufficient to expand production to the 90 MMT/year level, which is triple the 1984 demand level for compliance coal.

The compliance coal price will also increase the difference (i.e. premium) between the FOB mine price premium over high sulfur coal to \$14/ton, which is well above today's premium of \$1-\$3/ton. Much of this increase in coal premiums over today's levels will occur independent of acid rain legislation in response to stronger demand for Central Appalachian coal. With strong demand EVA believes the premium will rise to \$7-10/ton by the year 2000 without new legislation. The change due to acid rain legislation is expected to be \$4-7/ton. Given these price premiums, changes in demand for the various coal producing districts resulting from coal switching to are shown in the attached table.

COAL MINING EMPLOYMENT IMPACTS

The switching to alternative sources of coal supplies by the utilities to comply with the requirements of acid rain legislation results in increased demand for coal in some regions and decreased demand in other regions. However, the net change in employment for the total coal mining industry is an increase of 1,345 jobs, as shown in the attached table. This net increase in employment, while total industry demand remains relatively constant, is due to the fact that productivity (i.e., tons per manhour) varies among the coal producing districts.

Over the last decade, industry productivity has increased 185%. The primary driving force behind these productivity changes has been high costs and excess capacity within the industry. Although there are limitations on improvements in productivity, this general industry trend is expected to continue for an extended period of time in the future. Energy Ventures Analysis, Inc. in its private COALCAST reports carefully monitors these productivity changes for each coal producing region and forecasts future changes for each region. Expected future improvements in productivity have been incorporated in this analysis of changes in industry employment, except for eastern low sulfur coal producing regions.

Within the low sulfur producing areas of Central Appalachia it is anticipated that the industry trend of increasing productivity will change as a result of acid rain legislation. Demand for low sulfur coal in this region is projected to increase, which will strip the excess capacity within the region and cause prices to increase modestly. The combination of the reduction in excess capacity and higher prices will remove the major underlying forces behind the recent productivity

improvements within the region. Specifically, productivity for low sulfur coals (i.e., between approximately 0.75 and 1.0% sulfur) within the region is anticipated to remain at current levels, whereas productivity for Central Appalachia compliance coals (i.e., less than approximately 0.75% sulfur content) is anticipated to decline from current levels to approximately what the region achieved in the mid-1980's.

While the impact of acid rain legislation on total industry employment is relatively small, the impact on a few specific regions would be more extensive. The producing areas most adversely affected are the Illinois Basin and parts of Appalachia. Within Appalachia there is a tradeoff of jobs with the declines in Northern and Southern Appalachia more than offset by the increases in Central Appalachia. In Southern Appalachia, declines in employment as result of coal switching could be 27% of current coal mine employment, but would not occur until the year 2000. As a point of perspective, employment in Southern Appalachia has declined nearly 38% over the last decade as result of productivity improvements. In the future, as has been the case in the past, productivity changes are anticipated to have a more significant impact on the employment within this region than other factors, such as acid rain legislation.⁴

A similar perspective exists for Northern Appalachia and the Illinois Basin, although the percentage change in regional employment is not as great. For Northern Appalachia, in particular, the change in regional employment due to coal switching should be less than what has occurred over the last three years due to productivity improvements.

COMPARISON TO OTHER STUDIES

This study shows much less coal switching and coal mine employment impacts than some other studies sponsored by EPA, Alliance for Clean Energy and others. The differences in projected coal switching results are directly linked to the input assumptions made in each analysis that ultimately drive the end result. EVA believes that certain assumptions used by others are invalid and that the use of these assumptions results in more coal switching and less FGD scrubbing. Four major assumptions which account for many of the differences in the amount of coal switching are discussed below:

- (1) Lower high sulfur coal price: The higher the assumed high sulfur coal price, the more attractive coal switching becomes. EVA believes that high sulfur coal prices will be set by the dominate mining operations within a region, which will result in prices of \$25/ton FOB mine or less. EVA believes that higher prices are not justifiable in the high sulfur coal mining regions in the face of continued excess capacity and improved coal mine productivity. On the other hand, others project that prices for these coals will be much higher, since they assume prices are set by that mine price, which will make the last high sulfur coal mine to open economically viable.
- (2) Higher coal transportation rates for several individual stations: Coal transportation costs are a major component of coal switching costs and are a driving force behind utility

FGD scrubbing. EVA in its analysis has developed coal transportation rates for each high/low sulfur coal option to each coal fired station. Coal transportation rates vary widely based upon the carrier(s) involved, the movement's variable costs and individual station's ability to introduce more carrier competition. For many stations (e.g. minemouth stations, small truck delivery stations, etc.), the increased costs to transport low sulfur coals from other regions are significantly higher than barge delivery or multiple delivery stations. On the other hand, others often assume a single delivered price for a given coal type independent of the station and location involved. As a result, EVA believes that the transportation cost increase for Central Appalachian coals at many stations has been underestimated by others and this leads to an underestimation of coal switching costs and utility compliance costs.

- (3) Incorporates cyclone boiler coal switching constraints: EVA's study reflects that certain cyclone boilers and wet bottom boilers require low ash fusion coals to operate. While this limitation is easily met by high sulfur coals, the availability of low ash fusion low sulfur coals is limited to certain western regions. With limited coal switching options, these cyclone and wet bottom boiler stations have higher coal switching costs for more remote coals than PC stations and many will find FGD scrubbing more attractive. On the other hand, others assume no such coal switching constraints at these stations.
- (4) Limitation of coal quality on Eastern compliance coals: EVA has found that the vast majority of Central Appalachian coal reserves are unable to meet a 0.9# SO₂/MMBtu limitation and no supplier as yet has been willing to guarantee the 0.9# limitation. Others have assumed that Central Appalachian coals have a sulfur content of 0.9# SO₂/MMBtu or less. This results in a greater amount of coal switching and less scrubbing since stations can avoid reductions at peaking stations by burning subcompliance coals at larger stations.

In addition, as previously discussed, EVA believes that the industry trend towards improved productivity will be altered for the compliance and low sulfur coal producing regions as a result of acid rain legislation. The increased demand, along with the higher prices, for these coals will remove from the region the underlying forces behind the recent improvements in productivity - namely excess capacity and thin operating margins. Specifically, EVA believes for Central Appalachian low sulfur coals (i.e., between approximately 0.75 and 1% sulfur) that productivity will remain at current levels and exhibit no further improvement. Productivity for Central Appalachia compliance coals (i.e., less than approximately 0.75% sulfur), on the other hand, is anticipated to decline from current levels to approximately what the region achieved in the mid-1980's. The greater change in productivity for compliance coals is largely due to the greater reduction in excess capacity, as a result of the higher demand for this coal.

SENSITIVITIES

There are several sensitivities that could be performed on this study. One of the more interesting sensitivities is the price elasticity impact on the demand for electricity and how various legislative alternatives for acid rain would ultimately impact the demand for electricity as a result of price elasticity. While specifics are beyond the scope of this analysis, it is useful to note as a result of price elasticity for electricity, that a 0.9# SO₂/MMBtu acid rain requirement would constrain the growth in demand for electricity more than the 1.2# SO₂/MMBtu acid rain proposal discussed above. This lower electricity demand would result in less demand coal, which consequently mean less jobs within the coal mining industry.

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- 1 A study done by Energy Ventures Analysis, Inc. for the Electric Power Research Institute as a follow-up to the original study entitled "Coal Markets and Utilities' Compliance Decisions to be published April 1989.
 - 2 Although there are some specific regional distinctions, the following are the common categories of coal when referring to its sulfur content:
 - (1) Compliance coal is coal which can meet a 1.2# SO₂/MMBtu emission requirement. On percent by weight basis eastern compliance coals would have a sulfur content of approximately 0.75%.
 - (2) Low sulfur coal is coal which can meet a 1.3 to 1.8# SO₂/ MMBtu emission requirement and for eastern coals this is equivalent to a sulfur content between approximately 0.75 and 1% by weight.
 - (3) Medium and high sulfur coals are coals with emission levels greter than 1.8# SO₂/Btu. The distinction between medium and high sulfur categories can vary by region with high sulfur coals in general having emission levels in the 3 to 4# SO₂/Btu range, which is equivalent to approximately a 2.5% sulfur content.
 - 3 New Source Performance Standards (NSPS) apply to those plants for which construction began after 8/17/71 and before 9/19/78. Revised New Source Performance Standards apply to plants for which construction began after 9/19/78.
 - 4 Northern Appalachia incorporates Pennsylvania, northern West Virginia, and Ohio. Central Appalachia incorporates southern West Virginia, eastern Kentucky, Virginia and northern Tennessee. Southern Appalachia incorporates Alabama and southern Tennessee. The Illinois Basin incorporates Illinois, Indiana, and western Kentucky.

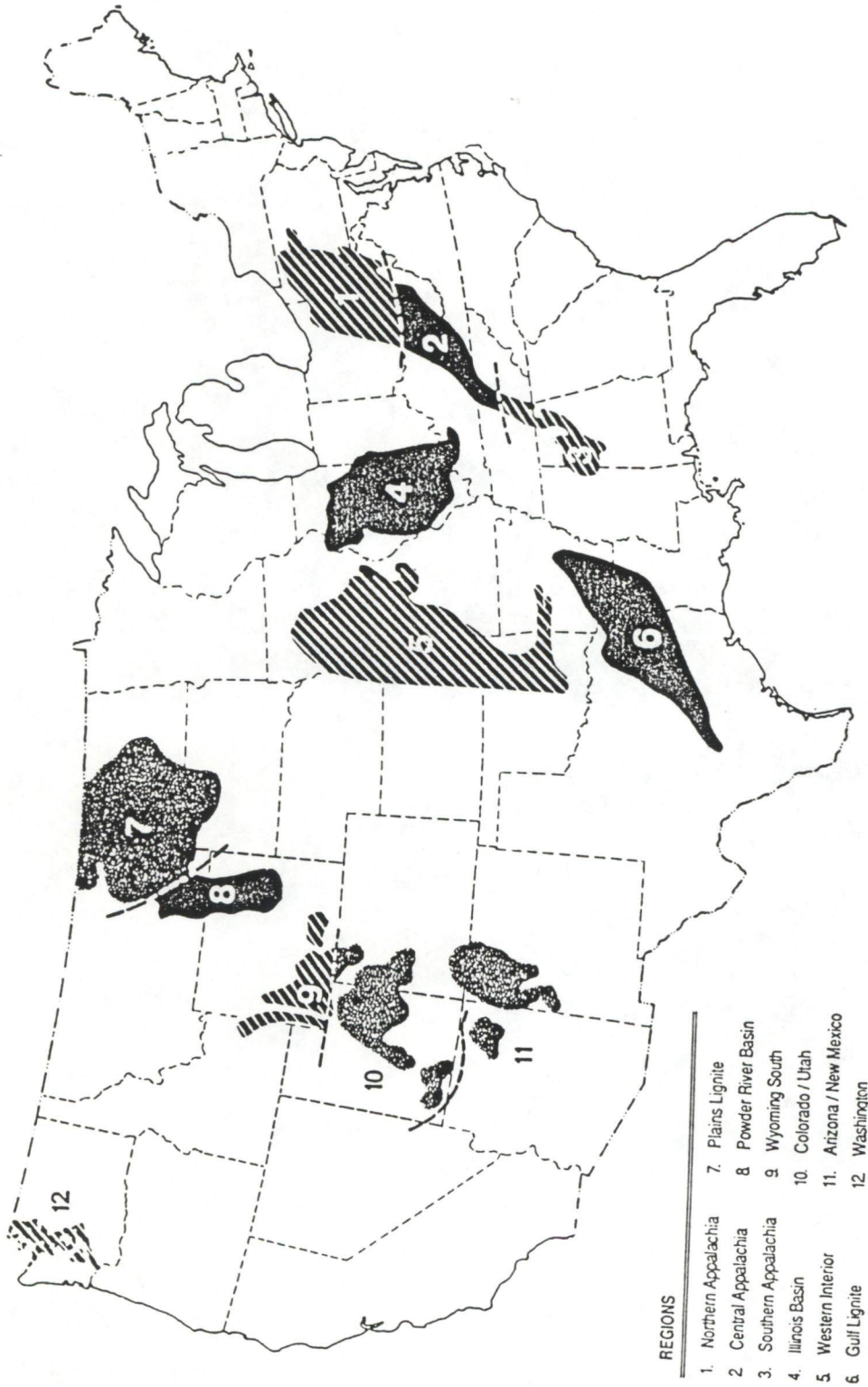


Figure 4-2 Coal Supply Regions

At the acid lake hearing

Edited exchange between National Acid Precipitation Assessment Project director James Mahoney and Democratic Sen. Daniel Patrick Moynihan of New York, Oct. 5, 1989, Senate Subcommittee on Environmental Protection.

Mr. Mahoney: If there were no change in acid deposition from current levels, we would expect that in the Northeast the chemical status of the lakes would stay approximately the same over the next 50 years.

Mr. Moynihan: You're saying that ... the lakes in the Northeast are in a steady state? Is that right?

Mr. Mahoney: Right.

Mr. Moynihan: Suppose we doubled the acid-rain deposition? Would that have any consequence?

Mr. Mahoney: Not much. We have a percentage of acid lakes (5 percent) and no matter what we do over the next century except for restoring them one at a time through liming, little is going to change that quickly.

Mr. Moynihan: Over the next century? So let's say we decided to get the most sulfurous coal conceivable out of West Virginia and Ohio ... and took all the scrubbers off [the smokestacks] and just banged away [with SO₂ emissions], that the present 10 percent of lakes would remain at an unacceptable acidic content, and the rest would remain OK?

Mr. Mahoney: That percentage would increase slightly ... it might be 11 or 12 percent.

Mr. Moynihan: So we are not dealing with a tender sensitive young organism that can change its condition. ... no matter what legislation we pass, about 10 percent of the lakes are going to be acidic beyond the lifetime of anybody in this room.

[Editor's note: One of NAPAP's problems is that a large share of acid lakes in the United States are in areas like Florida where there is little or no acid-rain deposition, suggesting that lake acidity has many other natural and geological causes independent of SO₂.]

Mr. Moynihan: You find a very high level of acidification of lakes in Florida. Is that right?

Mr. Mahoney: Yes, sir ... 22 percent of the lakes in Florida ... are acidic lakes

Mr. Moynihan: And this is not primarily associated, or even perhaps predominantly, with acid-rain deposition?

Mr. Mahoney: That's correct.

Mr. Moynihan: It has to do with the geology of the area, the plants?

Mr. Mahoney: Yes. And with the decaying organic materials introducing organic acids to the lakes

[Editor's note: Contrary to Environmental Protection Agency claims, most published research papers show that paleolimnological studies show that even in the Northeast, the majority of currently acidic lakes were acidic in pre-industrial times.]

Mr. Moynihan: If the present pattern of acid deposition continued unchanged ... what would happen to [lakes in the Northeast]?

Mr. Mahoney: If ... we look at the time 20 years from now and then 50 years from now, we see that if deposition is unchanged, we don't expect any significant change.

Mr. Moynihan: Now if we go to a decreased deposition [10 million-ton reduction], in 20 years we pick up 26 lakes?

Mr. Mahoney: Yes, sir.

see BROOKES, page F4

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CAA -

Acid Rain

BROOKES

From page F1

Mr. Moynihan: One lake a year. And we'd go from 5 percent down to 4 percent acidic lakes in the Northeast?

Mr. Mahoney: That's correct.

Mr. Moynihan: Over 50 years you'd pick up 80 lakes or 75?

Mr. Mahoney: Yes.

Mr. Moynihan: Well, what are the costs?

Mr. Mahoney: We are doing control cost estimates but we don't have them available at this time, so I can't make our own up.

Mr. Moynihan: Mr. Rosenberg? [William Rosenberg, deputy EPA administrator]

Mr. Rosenberg: We estimate about \$4 billion a year.

Mr. Moynihan: \$4 billion a year? OK, so we have to ask ourselves whether . . . that is the best way to spend \$4 billion a year. We could, with that money give every welfare family [in New York State] \$12,000 to vacation in the Adirondacks on some of the 95 percent of the lakes that are not acidic. Does it hurt to swim in acidic water?

Mr. Mahoney: No, sir, not in this range.

[Editor's note — Mr. Moynihan and Republican Sen. John H. Chafee of Rhode Island then had the following exchange with Walter Kretser, project director, New York State Adirondack Lakes Survey Corp., which deals with the uncertainty as to how many of those lakes were actually acidified by SO₂, and how many from reforestation since 1920.]

Mr. Moynihan: If you know the Adirondacks, it is kind of disillusioning to find out that it is not virgin forest. It was stripped bare. There wasn't a twig left when Theodore Roosevelt bought it for 10 cents an acre [in 1906]. We have since measured everything from the first robin to appear to the last leaf to drop from the yellow aspen. But the one thing they never recorded was the pH content [acidity] of the lakes. So if I asked you if there are more acidic lakes in the Adirondacks today than there were in 1900, you would have to answer.

Mr. Kretser: We don't know the answer to that.

Mr. Chafee: But if it is going to cost us \$4 billion to have these [SO₂ emission controls] . . . what is your recommendation to us about proceeding with those controls?

Mr. Kretser: I have no idea what the effect will be with SO₂ controls. A certain percentage of our lakes we expect would respond. We don't even know what that percentage is.

Mr. Chafee: Let me put it another way. Do you think that sulfur emissions have caused damage to the lakes you studied?

Mr. Kretser: A certain proportion, yes. But I cannot name that proportion.

Mr. Moynihan: People involved with the environmental movement . . . get very nervous when they hear the subject of research. . . . I would make the point that people who fear research might find out things that you don't want, or that they might be inconclusive. We went through eight years of the previous administration on acid rain and every time anybody went into the White House or the Office of Management and Budget and said they think we should do something, they were met with a fairly sophisticated inquiry of why. Invariably these questions had no response. There was no answer. And now we begin to know. In many ways it is very reassuring. It suggests to me that the sky is not falling. I am glad to hear that.

[Editor's note: Unfortunately the NAPAP report and testimony has so far not been heard or requested by any of the House subcommittees working on the acid-rain legislation.]

CLASSIFIED
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COMMENTARY

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WARREN BROOKES

On gold-plated ponds

A hearing on Oct. 5, members of the Senate Subcommittee on Environmental Protection discovered that the Bush administration acid rain program is experimentally futile.

A preview of the 1990 final report by the National Acid Precipitation Assessment Project shows the Bush proposal to spend up to \$4 billion to \$6 billion a year to cut sulphur dioxide emissions will decalcify only 26 lakes in the Northeast after 20 years—and only 75 lakes after 50 years. (See table.)

This means a 20-year cumulative cost of almost \$5 billion per decalcified lake and after 50 years about \$4 billion per lake. (By contrast, the 20-year cost of liming the average lake is less than \$50,000.)

In his report to the Senate, James Mahoney, NAPAP director, admitted that even this scandalously small

projection of benefits from the proposed Clean Air Program was iffy because: "There are significant uncertainties about the role that watershed mineral processes, organic acids and nitrates (in the soils) may play in the acidification and recovery process."

This is "science-ese" for admitting that, despite protestations, NAPAP knows there is very little correlation between acid-rain levels and acid lakes. For example, Mr. Mahoney acknowledged that the highest acid lake concentration in any U.S. state is in Florida. Yet Florida gets hardly any acid-rain deposition, and, as Mr. Mahoney noted, its acid lakes were the result of natural causes.

Also contrary to spurious "new (but unreleased) research" by the Environmental Protection Agency, published geological core studies

show that more than 80 percent of the acidic Northeast lakes were acidic in pre-industrial times.

Dr. Mahoney had to tell the Senate that "determining the precise percentage of acidic waters due wholly or in part to acidic deposition carries with it scientific and statistical uncertainties." This statement directly counteracted the propaganda with which EPA Director William Reilly had practically insisted that Mr. Mahoney lead his statement.

Mr. Mahoney granted that "the effects of constant, increased and decreased acid-rain deposition are not always statistically significant." Indeed they are not, either here or abroad.

In fact, the EPA's own data shows that land use and soil composition are at least three times as statistically significant "causes" of acidic lakes as acid rain.

The NAPAP analysis shows that acid rain is not a serious problem, and the costs of SO₂ reduction are ludicrously out of line with the benefits.

This is why NAPAP was forced to project that even if we do nothing, the number of acidic lakes in the Northeast will actually decline by one in the next 20 years, to a total of 161 and will only rise to 186 by the end of the next 50 years. Mr. Mahoney admitted, "What that really means, statistically, is no change at all."

Worse, even if we do as the Bush proposal suggests and cut SO₂ emissions by 10 million tons a year, raising electric bills in the Midwest by as much as \$900 a year in Ohio, \$630 in Indiana and Pennsylvania, \$520 in Missouri, and more than \$400 a year in Tennessee, West Virginia and Illinois, little will change.

When Democratic Sen. Daniel Patrick Moynihan of New York, a co-sponsor of the Bush Clean Air Program, heard this, he began to raise some carefully soft-spoken hell. "No matter what legislation we pass, about 10 percent of the lakes are going to be acidic beyond the lifetime of anybody in this room? We have to ask ourselves, is that the best way to spend \$4 billion a year?"

It is especially questionable when all of the lakes in North America could definitely be decalcified immediately by boat-liming, at a cost of less than \$400,000 a year total!

But what about other effects of acid rain on forests and crops? NAPAP Director Mahoney admitted: "Research has established that there is no measurable and consistent adverse crop-yield response from the direct effects of acidic rain at ambient levels in North America." On the contrary, "an evaluation of the nutritional enrichment of some agricultural soils through the input of sulfur and nitrogen from acidic deposition indicates indirect benefits associated with decreased fertilizer requirements."

But what about trees? NAPAP said that "other than for red spruce, extensive surveys of forest condition have indicated no evidence of widespread forest decline in North America related to acidic deposition."

Even on red spruce, NAPAP said the effects were limited to about 6 percent of the forests, all at high elevations (above 2,600 feet), and added, "Several natural stresses are related to these declines (droughts, freezes, diseases, etc.), and acid rain may intensify the effects of the natural stresses." (Emphasis added.)

In short, the NAPAP analysis shows now what it did in 1987: Acid rain is not a serious environmental problem (Mr. Moynihan concluded, "The sky is not falling"), and the costs of SO₂ reduction are ludicrously out of line with the benefits. It's a scandal waiting to be legislated.

Warren T. Brookes is a nationally syndicated economics columnist.

THE HIGH COSTS OF REDUCING ACID RAIN

	This year	Number of acidic NE lakes	Cumulative costs of SO ₂ reduction	Cumulative costs to lime all NE acidic lakes
20 Years From Now	162	161	\$4.6 bill./yr.	\$400,000/yr.
■ No Program		161	—	—
■ Liming		0	—	\$8 million
■ Bush Program		136	\$120 billion	—
50 Years From Now	186	186	—	—
■ No program	0	—	—	\$20 million
■ Liming	87	—	\$300 billion	—
■ Bush Program		—	—	—
20-year Cost per Lake Changed From Present				
■ Liming			\$5 billion	\$50,000
■ Bush Program			—	—

Source: Based on NAPAP Oct. 5, 1989 Report. Senate Subcommittee on Environmental Protection.

Clean Air Act - Acid Rain

Study of Acid Rain Uncovers a Threat To Far Wider Area

Damage to lakes and
streams found in
East and Midwest.

1/14/90 NYT
By WILLIAM K. STEVENS

A HUGE Federal study has found that acid rain has turned many lakes and streams acidic not only in the Northeast but also in other areas of the East and parts of the Midwest, including northern Florida, the Appalachians and the New Jersey Pine Barrens.

But the findings are not all bad. The researchers said the overall acidification of the nation's waters was less extensive than was feared when the research began a decade ago.

"In the late 1970's, there was probably more alarm than is justified by what we currently see," said Lawrence A. Baker, an environmental engineer at the University of Minnesota Water Resources Center, the chief author of a new report in the section of the Federal study that deals with acidified lakes and streams.

But in six areas of the country, the researchers have determined, acidification of lakes and streams is sufficient to merit special attention.

"If I were living in one of them and was interested in water and recreation, I'd be concerned," Dr. Baker said in a telephone interview from the Environmental Protection Agency laboratory in Corvallis, Ore., where he has led the preparation of the report.

28 Reports Under Review

The six areas where the researchers found cause for concern are the southwestern Adirondacks, New England, the Atlantic coastal plain, contiguous parts of northern Wisconsin and the Upper Peninsula of Michigan, the Appalachians nearly as far south as North Carolina and the northern Florida highlands.

The study is one of 28 "state of the science" reports that are being circulated by the National Acid Precipitation Assessment Program, a multi-agency project created by Congress in 1980 to provide a definitive understanding of the acid-rain problem. The reports are still being reviewed by other scientists and could be revised, but they are designed to pro-

vide the grist for a final report that the program plans to deliver this year.

Acid rain is an overall term for rain, sleet, snow, mist, fog and clouds containing sulfuric acid and nitric acid produced by the burning of coal, oil and gasoline. The precipitation has made many lakes and streams so acidic that much aquatic life cannot survive in them.

The findings on acid lakes and streams are based on an extensive survey of surface waters in parts of the country where acidification was suspected to be a problem, mostly in the East and Midwest but also in the Western mountains, from 1984 through 1986. Of an estimated 28,346 lakes in those areas, 2,311 were tested. A sample of 500 streams, representing an estimated 124,280 miles of stream reaches, was also tested.

Lakes and streams vary in their vulnerability to acidity, depending on how alkaline they and the soils in surrounding watersheds are.

The survey found that 4.2 percent of the lakes in the study were acidic. The researchers calculated that this represented 1,181 lakes over all, most of them in the Northeast, Florida and the upper Midwest. They found that inorganic sulfates of the kind produced by the burning of fossil fuels, borne by precipitation, were the dominant source of acid in those waters.

But the numbers were much higher in what the report calls the six "high-interest regions," which together accounted for almost all the acidic lakes and streams where acid rain was the main factor.

Extent of Damage in 6 Areas

In roughly the southwestern third of the Adirondacks, the researchers found that 38 percent of the lakes were acidified (no acidified lakes were found in the rest of the Adirondacks); in the seaboard lowlands of New England, 8 percent; in the Appalachians, 10 percent; in the Atlantic coastal plain, 11 percent; in parts of northern Wisconsin and Michigan's Upper Peninsula, 16 percent; and in the northern Florida highlands, a surprising 56 percent.

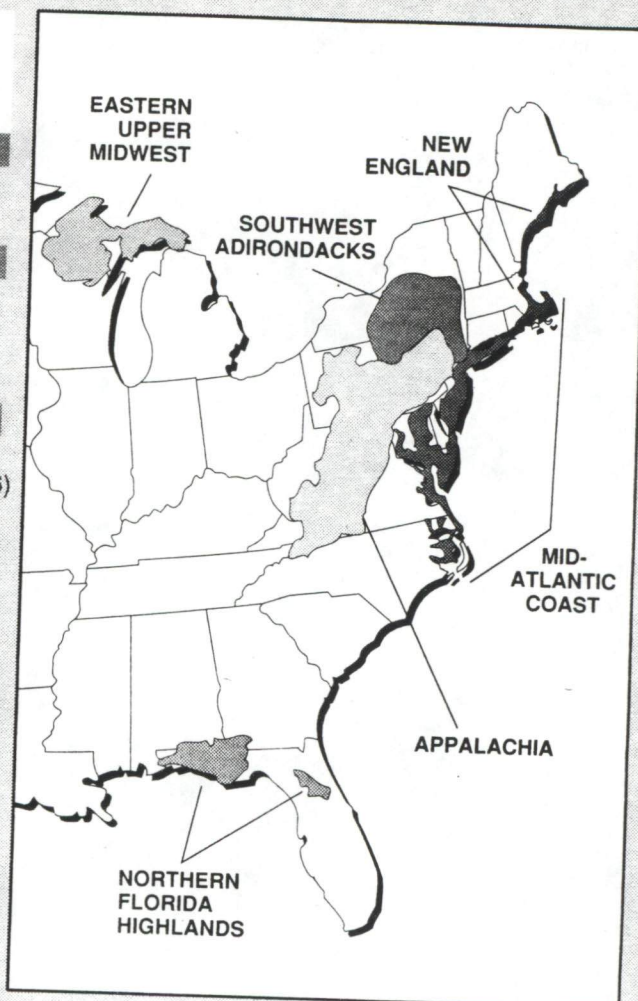
The study determined that 2.7 percent of the streams in the national survey were acidified. But in the Appalachians, the proportion was 12 percent; in northern Florida, 28 percent; in the New Jersey Pine Barrens, 56 percent.

The researchers also found that in the southwestern Adirondacks, 51 percent of the lakes registered a pH of 5.5 or less, a level of acidity at which damage to some aquatic life is believed to begin. The lower the pH,

Acid Rain: Troubled Areas

An extensive Federal research program on acid rain has found that six regions merit special attention because of damage caused to lakes and streams.

Area	Number of lakes over 10 acres	Percent acidified (number of lakes)
ADIRONDACKS		
Southwest Lakes	450	38% (171)
NEW ENGLAND		
Seaboard Lowlands Lakes	848	8% (68)
Highland Lakes	3,574	2% (71)
APPALACHIA		
Forested Lakes	433	10% (43)
Forested Streams	11,631	12% (1,396)
ATLANTIC COASTAL PLAIN		
Northeast Lakes	187	11% (21)
Pine Barrens Streams	675	56% (378)
Other Streams	7,452	10% (745)
FLORIDA		
Northern Highland Lakes	522	63% (329)
Northern Highland Streams	669	28% (187)
EASTERN UPPER MIDWEST		
Low Silica Lakes	1,254	16% (201)
High Silica Lakes	1,673	3% (50)



Source: National Acid Precipitation Assessment Program.

The New York Times/Jan. 16, 1990

Six areas of the U.S. accounted for almost all the acidic lakes and streams.

the more acid is the water. A pH of 7, the acidity level of pure water, is neutral. Lemon juice has a pH of 2.

More than half the lakes and streams in northern Florida were found to have a pH of 5.5 or lower, as were 17 percent of forested streams and 9 percent of forested lakes in the Appalachians, and 92 percent of streams in the Pine Barrens of southeastern New Jersey.

In the case of the lakes, Dr. Baker said, the numbers could actually be higher. This is because the survey in the eastern half of the country includ-

ed only lakes larger than 10 acres.

Many are smaller, and the report notes that a study by the Adirondack Lake Survey Corporation, which Dr. Baker called "a good, valid study," determined that 35 percent of Adirondack lakes smaller than 10 acres were acidified. But while this could double the estimated number of acidic lakes in that region, he said, smaller lakes tend to be more influenced by natural acids.

Dr. Baker said the stream survey did not include any streams in large parts of the Northeast, "and we can reasonably expect that approximately 5,000 kilometers," or 3,100 miles, of streams in that area would be acidic.

Acidification of lakes in the Northeast and upper Midwest has been attributed to emissions from Middle Western power plants. Legislation now before Congress, sponsored by the Bush Administration, seeks to cut those emissions substantially.

Dr. Baker said the surprisingly high proportion of acidic lakes in Florida appeared to be largely a re-

sult of coal-burning power plants in the state.

In the Northeast, little further chemical change in lakes is expected because they are already at a steady state, James R. Mahoney, the director of the acid rain research program, has testified before Congress. He said that if acid precipitation on the lakes were cut by 30 percent, about half the lakes that are now acidic would improve in time.

A few acidic lakes in the United States, and many in Sweden, have been brought back to life by simply adding limestone to them. Another state-of-the-science report now undergoing review says essentially that "liming," as it is called, works and is the most effective method for neutralizing the acid.

It estimates that more than 2,500 lakes and 22,000 miles of streams, with varying degrees of acidification, may be candidates for liming, and that many more would be candidates in Canada and Sweden.

Acid Rain: Plenty Bad Enough

NY 1/29/90

The rain that falls over much of the northeastern United States is mildly acidic from pollutant gases. Like many weak poisons, its effects are subtle and hard to pinpoint. The preliminary results of a monumental 10-year Federal study now establish just how harmful this acid deluge is. They lend urgency to proposals now before Congress that coal-burning utilities sharply cut their emissions of acid gases.

The \$500 million study — known as the National Acid Precipitation Assessment Program — began in 1980 and seven years later produced a much criticized interim report. In accord with the Reagan Administration's belief that acid rain was not a serious problem, the interim study indicated that no more lakes were likely to become acidified and damage to trees was highly unlikely.

Drafts of the final report, as William Stevens has reported in *The Times*, paint a darker picture. Acid rain is not about to cause the sudden ecological collapse predicted by some accounts in the early 1980's. Lakes are acidifying over decades, not seasons. But acid rain is indeed a serious threat to the ecology, especially in regions where the soil lacks a natural capacity for neutralizing acid.

In the southwestern Adirondacks, 11 percent of lakes are already acidified and 36 percent in danger of becoming so. In Appalachia, the Atlantic coastal plain, and parts of Wisconsin and Michigan, some 10 percent of lakes and streams have already been acidified past the point at which ecological damage is likely.

The draft report does not settle the longstand-

ing issue of the widespread decline in some American forests. It finds no evidence to link forest decline in North America to acid rain, other than for high-altitude red spruce. With these trees, acid rain seems to worsen natural stresses. But acid rain may reduce the fertility of some forest soils over the long term.

Opponents of acid rain control have argued that all the lakes likely to go acid have already done so, and that reducing acid rain won't revive any of them. But James Mahoney, director of the study, told a Senate committee last year that more streams could acidify at current levels of pollution. And, significantly, he said that cutting pollutants by 30 percent would allow the recovery of half the acidified lakes in the Northeast.

•

The National Assessment will not be completed until later this year, but the politics of acid rain seem to have been settled, at least in broad outline. President Bush has proposed reducing sulfur dioxide emissions by 10 million tons each year. Congress and even electric utilities have accepted the goal and are now arguing about how to implement it.

Political solutions should follow, not precede, scientific conclusions, especially conclusions reached at the cost of \$500 million. Fortunately, the National Acid Precipitation Assessment Program has already provided ample evidence for acting to curb acid rain.

REVIEW & OUTLOOK

No Pap From NAPAP

1/24/90 WJS

The following editorial contains the results of scientific research and so may be inappropriate or offensive to those who conduct environmental policy in Washington, D.C. Reader discretion is advised.

The results of the National Acid Precipitation Assessment Program are trickling into public view. Science now knows more about acid rain than it used to. NAPAP is a 10-year-long, government-sponsored study involving hundreds of scientists and costing more than \$500 million. It is the definitive statement on the acid-rain problem. Its report is not final and has not been released but some of its conclusions are circulating through the press and scientific community.

It appears, for instance, that except for red spruces high in Northeastern mountains, acid rain does not directly harm trees or other vegetation. Acid rain does impose indirect stress on trees, but that stress is minor compared with that caused by other factors, such as temperature, insects, root diseases and ozone. Nor does acid rain reduce crop yields.

Acid rain does affect lakes, though exactly how much is not completely understood. Many lakes have been naturally acidic since prehistoric times. In Florida, for example, 22% of the lakes are acidic, but Florida has little or no acid rainfall.

Nevertheless, in many areas where soils are naturally acidic, the organic sulfates that are produced by burning fossil fuels do further reduce the pH level, sometimes significantly. A separate section of the report, still under review, indicates that putting lime into lakes is the most effective way to neutralize the acid. It is certainly the cheapest.

Senator Daniel Moynihan, who wrote the bill creating the NAPAP study in 1979, summarized the study's results this way: "To me, it's reassuring, because it shows that the sky is not falling."

The NAPAP results expose the irresponsible hysteria fomented by environmental groups, and encouraged in hyperventilating media reports. A lot of people have a lot of explaining to do about their statements on the severity of the problem, not least EPA head William Reilly and other authors of the Bush Clean Air Bill who produced their legislation before the NAPAP results were released.

The Bush acid-rain provisions would cost the U.S. at least \$4 billion

a year, according to the EPA. Can this spending be justified in light of the NAPAP findings? For millions, not billions, it would be possible to lime all the artificially acidified lakes in the country. Wouldn't this be the more financially prudent course, until the NAPAP folks have nailed down the full acid-rain story? Assuming, of course, that anyone in Washington can still think in terms of financial prudence on environmental issues.

Voters outside the Beltway should certainly hope so. Under the acid-rain provision of the House bill, which is substantially the same as the Bush bill, Ohioans will have to pay an extra \$898 million in their utility bills. Georgians will have to pay an extra \$396 million, West Virginians will pay \$417 million. These figures come from the Edison Electric Institute and, even allowing for the fact that they may be high-end estimates, the costs are surely staggering.

In addition, the acid-rain provision would add \$5 a ton to the price of domestically made steel, and 4 cents a pound to domestically made aluminum, thus damaging the competitive posture about which such men as Rep. Gephardt and Sen. Mitchell profess concern. Immediate capital costs required by the legislation would also divert investment from efforts to modernize industrial plants.

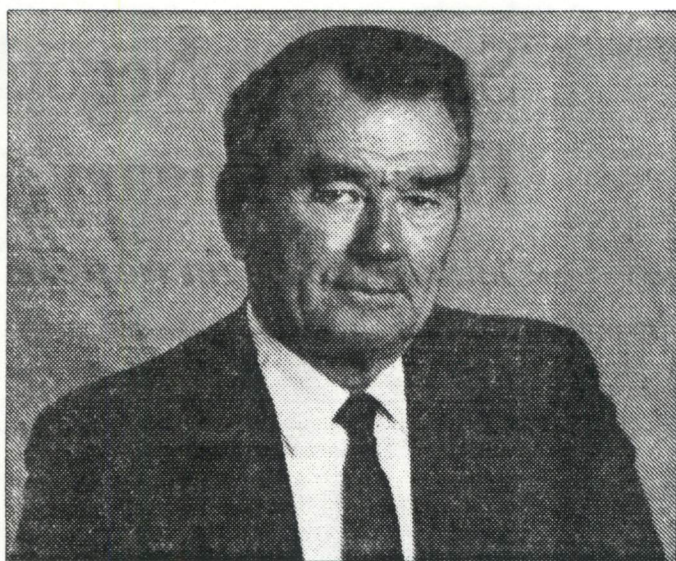
The kicker is that the bill will have only a slight effect on acidified lakes. NAPAP Director James Mahoney recently testified that the Bush bill emissions cap would mean that after 20 years, 25 lakes in the Northeast would be deacidified—a cost of more than \$3 billion to deacidify each lake. Sen. Mitchell and the environmental acolytes who staff the Senate environmental committee have written an even more expensive acid-rain provision. The Senate bill would move up compliance dates, demand stricter nitrogen-oxide reductions and reduce allowances for new power plants.

The White House could achieve any immediate pay-back on the public's investment in the environment by announcing an immediate program to begin liming the lakes, based on the NAPAP results. It would constitute a rational, interim acid-rain policy, spare Congress a tumultuous debate over costs, save the American people billions of dollars a year in needlessly higher utility costs, and, though this may seem trivial in Washington, the lakes actually would be enhanced.

1/23/90 WP

CLA - Acid Rain

Cutting Off Coal To "Cure" Acid Rain Could Short Circuit America's Electrical System.



My name is Kenneth Barr.

My company is Cyprus Minerals Company. We supply raw materials to basic industry from nearly 50 locations in 23 states. I've talked to many members of Congress over the last few years about the importance of avoiding legislated cost increases. My message has been and still is the same:

"Don't make it any harder to compete in the world than it already is."

A handwritten signature in cursive script that reads "Kenneth J. Barr".

Wishful thinking will not generate electricity. Coal will.

The President's Clean Air bill is a good start. Phase I of Acid Rain provisions reduce sulfur emissions while allowing growth in the use of our most plentiful energy source — coal — with the flexibility to minimize costs. The problem is that Phase II includes emission caps which restrict the growth of coal use and increase costs. It also imposes tight deadlines that will not allow time for implementing

Can we afford to restrict coal use when...

...Nearly 60% of our electricity is generated by coal?

...Nuclear power plant construction is on hold?

...Sites for hydro-electric plants are scarce and off-limits?

...Oil imports exceed 50% of our oil needs and are climbing?

...Natural gas supplies to generate electricity are less than coal and more costly?

...The system is already tight, as shown by electric power shortages during December's record cold weather?

Can we afford the risk of costs higher than necessary to achieve clean air goals when...

...Our worldwide competitiveness is still in question?

...Our trade deficit is still a problem?

...Our budget deficit is depressing our growth?

advanced clean coal technology.

A Phase II emissions standard of 1.2 pounds of sulfur per 1 million BTUs, as announced by the White House on June 12, 1989, and adjustment of compliance deadlines will reduce the cost of cutting sulfur emissions about 10 million tons a year, while allowing growth in the use of clean coal.



**CYPRUS
Minerals Company**

Box 3299 / Englewood, CO 80155

Now Is Not The Time To Foreclose Growth In The Use Of Coal.

Last Gasp for Bush Clean Air Reforms

WSJ 11/7/89
By ROBERT W. HAHN

President Bush sent Congress a clean air bill this summer that contained two innovative and controversial reforms. Both would have led to significant reductions in air pollution while, in the president's words, "harnessing the power of the marketplace." One of those reforms has already been killed on Capitol Hill. The other is in serious danger.

The president's approach moves beyond traditional "command-and-control" regulations, which mandate particular pollution control devices such as scrubbers for power plants. Instead, business and consumers would decide for themselves how best to achieve emissions reductions, so long as they met federal standards. For example, to reduce auto pollution, the president's program would allow car makers to trade emission reductions across vehicle categories and among manufacturers. If a manufacturer produced a car that polluted less than the federal standard, it would have a valuable emission credit, which it could sell or use on another vehicle. Auto makers would have an incentive to try alternatives to the gasoline powered engine, such as methanol.

A similar arrangement would govern the emissions that have been tied to acid rain. The president's bill calls for annual emissions reductions of 10 million tons of sulfur dioxide and 2 million tons of nitrogen oxides by the year 2000. The flexibility it allows firms in meeting these goals will save the economy at least \$13 billion.

These innovative reforms would build on two more limited programs pioneered by the Environmental Protection Agency in the late '70s and '80s. The first, an emissions trading program aimed at reducing pollution in areas that exceed federal standards, has resulted in billions of dollars of cost savings for consumers, ratepayers, and shareholders without sacrificing environmental quality. The second, a flexible program for phasing out lead in gasoline, resulted in savings of over \$200

million annually while eliminating a significant health risk.

Despite these successes, flexible approaches have been viewed as sacrilege by virtually all environmental groups, with the recent exception of the Environmental Defense Fund. Congress too remains distrustful of using markets to solve environmental problems. Markets may improve the environment and save money, but they also reduce the ability of bureaucrats and congressmen to decide how and where resources will be spent.

Rep. Henry Waxman (D., Calif.), Chairman of the Subcommittee on Health and the Environment, helped engineer the demise of the vehicle emissions trading program. Mr. Waxman would rather stipulate the measures that must be taken: reduced tailpipe emissions, sturdier catalysts and other gadgets, even though these contraptions are unnecessarily expensive—EPA estimates that the tailpipe controls alone will cost an additional \$600 per car—and discourage creative thinking about alternative engine designs and fuels. Mr. Waxman also complained that a flexible approach for meeting environmental standards implies that some firms will reduce pollution by more than the average and some by less. This, apparently, was intolerable: firms cannot be doing their "best" unless they are all above average.

Congress is now working on a law of its own in response to the president's bill. The need to satisfy both environmentalists like Mr. Waxman and auto state legislators like Rep. John Dingell (D., Mich.) is producing a dangerously rigid compromise, as can be seen from the congressional adoption of two sets of virtually identical controls to prevent the fumes from gas pumps from entering the atmosphere. The administration proposed a vapor control system on nozzles at the pumps because it would be less expensive to install. Congress agreed—and then required a vapor control system to be installed inside cars as well. A recent study reveals that adding onboard

systems after the pump vapor controls are in place would actually increase emissions!

Some flexibility may yet be retained in meeting acid rain goals. But even here, individual Congressmen have taken out the howitzers. The assault rests on the faulty proposition that markets do not work. Critics of the president's proposal fall into two camps: 1. Those who argue the market won't work because they don't like the ambitious targets set forth in the administration bill; and 2. those who believe electric utilities, the principal source of acid rain emissions, will hoard emission permits to preserve future growth opportunities. Such hoarding, it is argued, will impede growth in this vital sector of the economy.

The Council of Economic Advisers has pointed out that such hoarding is unlikely because a robust market in trading permits for sulfur dioxide emissions will emerge. If the council turns out to be wrong, there is a simple safeguard that would insure that new plants could purchase emission permits: Have the government retain and sell a small fraction of the permits to all interested buyers or those buyers planning to increase capacity. The proceeds of the auction could go to the government, or could be distributed on a pro-rata basis to existing permit owners.

As Congress engages in the unseemly business of making sure that special interests are satisfied, the president's two innovative environmental reforms could easily disappear, or be gutted. Be assured that the environmentalists and powerful industry lobbies will get their slice. The danger is that in the process, Congress will eliminate the foundation on which the president's reforms rest—"harnessing the power of the marketplace" to meet both environmental and economic needs.

Mr. Hahn an associate professor at Carnegie Mellon, worked for the past two years on environmental issues on the staff of the Council of Economic Advisers.

Dingell Acid-Rain Plan Spreads Cleanup Costs

Large Utilities as Well as Dirtiest Power Plants Would Pay

11/3/89 WP
By Michael Weisskopf
Washington Post Staff Writer

The House Democratic sponsor of President Bush's clean-air bill yesterday unveiled a plan for acid rain controls that appears to contradict the cardinal principle of the administration measure, which is that the polluter pays.

The plan by Rep. John D. Dingell (D-Mich.), chairman of the House Energy and Commerce Committee, comes three weeks after he led a move to gut another key provision of the Bush package that would have required alternative auto fuels to reduce smog.

On acid rain, the administration bill would require power plants by the year 2000 to halve their emissions of sulfur dioxide, which combines with water in the air to form acid that comes down in rain, poi-

soning lakes and damaging forests in the Northeast.

The nation's dirtiest plants—107 facilities in the Midwest and Southeast—would be responsible for all the reductions in the first five years and for the costs of cleanup.

Dingell's plan, however, would spread out the cleanup costs—estimated to run \$700 million a year in the first five years—by assessing fees from other large utilities, industrial boilers and processors based on their emissions of sulfur dioxide. The fees would be used to pay part of the costs of anti-pollution devices installed by the dirty facilities.

The administration strenuously opposes similar cost-sharing programs but had no comment yesterday on this version.

Dingell's plan is designed not only to ease cost burdens for rate

payers in the Southeast and Midwest, who would otherwise shoulder the entire cleanup cost, but to save jobs of high-sulfur coal miners in those regions.

Anti-pollution devices remove enough sulfur to allow utilities to continue to burn high-sulfur coal and still meet the new air pollution requirements.

Under the administration bill, the dirty plants would be free to choose any method to reduce emissions. Without subsidies, most were expected to turn to low-sulfur coal mined in the West because using it would be cheaper than installing cleanup technology.

A major shift to low-sulfur coal could wipe out as many as 30,000 high-sulfur coal mining jobs by the end of the century, according to the Environmental Protection Agency.

See AIR, A7, Col. 1

Program Seen Easing Cost Burden For Rate Payers in Southeast, Midwest

AIR, From A6

Dingell, who represents a heavily unionized district in the Detroit area, has expressed concern for the coal jobs at risk in the Bush bill.

A Dingell spokesman said the plan is designed to be "consistent with the general approach" of the Bush bill because its subsidies for the dirtiest plants would come from other sulfur dioxide emitters, in line with the principle of making the polluter pay.

He said the plan does not veer from the president's proposal to halve sulfur dioxide discharges, and sets a nationwide cap on emissions at 1980 levels after the year 2000.

Another provision of the plan designed to help utilities meet increased electricity demand in fast-growing regions raises questions

about Dingell's commitment to the nationwide cap, which is considered the most far-reaching facet of Bush's bill.

Dingell's plan would extend to industrial boilers and processors the system of emission reduction credits that the president has proposed for the 107 utilities. Under the Bush proposal, any utility able to cut emissions beyond the prescribed levels would be able to sell those credits to utilities seeking to expand emissions in growth states.

According to Rep. Henry A. Waxman (D-Calif.), the plan to give credits to boilers and processors in return for their fee—not in return for cutting emissions—would put so many credits into currency that emissions would increase beyond the cap, if all credits were used.



REP. JOHN D. DINGELL
... plan designed in part to save jobs

THE WHITE HOUSE
Office of the Press Secretary

For Immediate Release

March 13, 1990

FACT SHEET
THE PRESIDENT'S CLEAN FUELS PROGRAM

President Bush today reiterated his continued support for the inclusion of a strong clean fuels program in the Clean Air Act reauthorizing legislation now pending in the Congress.

The clean fuels program was first proposed by the President in July 1989. The proposal is designed to provide a long-term reconciliation of the environment and the automobile -- so that Americans can continue to enjoy economic growth, freedom in using their automobiles, and clean air.

In pressing forward with support for a clean fuels program, the President recognizes that several cities continue to face severe ozone pollution problems. The President's clean fuels program combined with other controls in his bill will shrink the contribution of vehicles to the ozone problem from 40% to 10%. It would also result in significant reductions in air toxic emissions.

PRINCIPLES

The President's clean fuels plan is built on several basic principles:

1. The program should provide for significant reductions in smog-producing and air toxic emissions.
2. Fuels and automobiles should be viewed as one system, from which smog-producing and toxic emissions must be reduced.
3. Any clean fuels program should be fuel neutral -- that is, any fuel which results in cleaner air should qualify: including ethanol, methanol, reformulated gasoline, natural gas, electricity, liquid petroleum gases, and others.
4. The clean fuels program should be targeted at those cities with the worst smog problems where clean fuels will

provide the greatest environmental benefit, and where it will be the most difficult to achieve the ozone standard without a clean fuels program.

5. The program should be designed to achieve the maximum environmental benefits, with adequate flexibility to ensure that the reductions are cost-effective.

6. The program should rely on market forces as much as possible.

THE PRESIDENT'S PLAN

The President's plan:

- o Is targeted to the 9 major metropolitan areas with the worst smog problems, but provides opportunities for other cities to "opt-in" to the program if it will help them achieve environmental standards.
- o Will require minimum performance criteria for reductions of both smog-producing ozone and toxic air pollutants. The performance standards will be tightened in future years as fuel technology advances.
- o Will require, for the first time, mandatory reductions in air toxic emissions from cars and trucks.
- o Will require that clean fuels be available in America's most smog-filled cities -- thus achieving greater ozone and air toxic reductions in these cities at less cost than an expensive nationwide second-round tailpipe control mandate.
- o Will require that all new buses in America's largest cities operate on clean fuels, sharply reducing particulate emissions from these buses.

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THE WHITE HOUSE

Office of the Press Secretary

For Immediate Release

March 13, 1990

REMARKS BY THE PRESIDENT
AT ALTERNATE FUEL DEMONSTRATIONSunoco Station
Southeast Washington, D.C.

2:15 P.M. EST

THE PRESIDENT: Obviously the reason we're here today is to show the interest we all have -- industry, the administration -- in cleaner air. There's no question about that, and that's why I came over here today. This is the first commercial availability of methanol in the Washington area.

I want to commend the Sun Company for taking this leadership role in helping our national efforts to reduce air pollution. And I want to thank Mr. McClements himself, the Chairman, for being with us, and I would salute not only him but Ray Poling of the Ford Company, who has taken out his busy schedule to be with us here today, explain how all of this works in an automobile. I want to thank Chuck Imbrecht and Bob Hahn, the co-chairmen of the Alternate Fuels Council, for being with us.

The clean air legislation that I proposed last year is going to go a long way toward achieving our environmental goals. And a fundamental part of this, an integral part of this program is the Clean Fuels Program. We're working hard, and I want to, again, thank both sides of the aisle in Congress, in a bipartisan way, to enact the legislation. The Senate leadership and I, along with our top officials here, Henson Moore of the Energy Department and Jim Watkins, the Secretary, Bill Reilly of EPA, John Sununu and others have all agreed with us on goals and on methods that will achieve our plan.

And a variety of clean fuels, no question, can help to reduce urban smog and toxic air emissions. This, in turn, is going to reduce the regulatory burden on a wide range of small businesses out there. The availability of methanol in a metropolitan area, say, like Washington, is an important step toward the widespread use of clean fuels. There are other -- a few clean fuels in addition to methanol. Click off a couple -- natural gas, propane, ethanol, reformulated gasoline and then electricity. The flexible fuel vehicle that we see here today, one of Red's cars -- a Ford Victoria -- is a government fleet vehicle. By using alternative fuel vehicles, the federal government is trying to lead by example.

And at this time, I again want to thank both our CEOs that were here with us today. Under the direction of the Interagency Commission on Alternative Fuels that is chaired -- Henson Moore chairs that, the Deputy Secretary of Energy -- we're moving forward to bring more alternative fueled vehicles into our fleet. The Interagency Commission and its advisory body, the U.S. Alternative Fuels Council, have an important job in helping develop a national alternative fuels policy.

This is a part of our overall answer to those who worry about cleaning up the environment, as we do. It's a step; it's not the cure-all and the end-all. But I want to congratulate industry -- in this instance, the Saab Company, Ford Motor Company -- for showing fine leadership. And we will keep working with the Congress to accomplish this first major revision in the Clean Air Act since it was first written. It's sound for all of our country. And I'm

MORE

delighted with the bipartisan support we've been getting. So thank you all. (Applause.)

Q Mr. President, haven't you already backed off the requirements for alternative fuel vehicles?

THE PRESIDENT: You know, I've discovered something. Nobody ever does it exactly the way I want it done. But what we have is a sound, strong, environmentally secure compromise that has the support of the best environmentalists I know of. And we're never going to placate those on the extreme side of the equation that want to do nothing, or want to just shut down this country and throw every American that's got a job out of work. We've come to a good compromise, a strong compromise.

And so yes, I can fine tune it, gripe about one phrase and one section or another, but I'm not going to do that. And I'm encouraging our Senators -- both sides -- to get behind this and move it out and then get prompt action in the House.

Q But you've already thrown in the towel on a million alternative vehicles.

THE PRESIDENT: We've thrown it in and we're doing well, and people who take a look at it know that we've got a good sound bill that's going to help clean up the environment. First -- biggest breakthrough since the Clean Air Act was written. And it isn't one that's going to throw America out of work. So, don't worry about that. Don't listen to the extremes on this question. Okay.

END

2:25 P.M. EST



CQA - Alt. Fuels

FACSIMILE TRANSMITTAL SHEET

THE FOLLOWING TRANSMITTAL IS BEING SENT BY:

Name: Bill HumberDate: 3/5/90# Of Pages Including Cover: 4

FOR IMMEDIATE DELIVERY TO:

Name: Boyd Gray -Company: White House. 456-2883

- ☐ For your information
- ☐ For your comments
- ☐ Please call me about this
- ☐ As you requested
- ☐ As we discussed
- ☐ Memorandum
- ☐ Press release

☐ Notes: Boyd - You werebriefed on this. Note the economic
and environmental benefits.

Tech Notes

Bringing Diesel Up to Snuff Without Alternative Fuels

By JOHN HOLUSHA

FUEL SOOT-belching city busses is needed for extinction as a result of stringent Federal emissions standards due to go into effect next year. Buses in urban areas may emit as much as 0.6 grams of black carbon particles per horsepower of the engine for each mile driven, that allowance will be cut to one-tenth of a gram next Jan. 1.

Such alternative fuels as methanol and compressed natural gas have been advanced as the solution to the clean-up problem, and test programs involving both are underway in New York and elsewhere. The Federal Environmental Protection Agency has imposed the standards on transit systems three years before the same rules are to apply to all heavy-duty diesel engines to encourage

large scale testing of alternative fuels.

Since buses return to a central storage and fueling facility each day, only one alternate fuel tank and pumping facility would have to be installed to service them, as compared with a nationwide infrastructure needed to service over-the-road trucks. But alternative fuels will require costly modifications to bus engines and servicing facilities, deliver fewer miles per gallon and may cut into passenger carrying capacity.

As a result, many bus fleet managers will simply stop buying new buses after Jan. 1 until the advantages and drawbacks of alternative fuels become clearer, according to a survey last year by the American Public Transit Association. One association member, the Golden Gate Bridge Highway and Transportation District, based in San Francisco, estimated that converting to methanol

would add an additional \$31,260 a year to the \$130,000 annual cost of operating each bus.

This quandary may provide an opportunity for a small, Redcliffe, Iowa-based entrepreneur who has developed a system that may be able to bring standard, diesel-fueled engines into compliance at a relatively modest cost.

The system, developed by a company called Midwest Power Concepts, injects low-proof ethyl alcohol, also known as ethanol, into the engine. At the same time, it reduces the amount of diesel fuel flowing to the engine's cylinders. Warren M. Dobbervin Jr., Midwest Power's president, said the partial substitution of ethanol for diesel fuel eliminates the overheating that is responsible for the black cloudbursts from the exhaust pipe when a diesel engine is heavily accelerated. The water and alcohol mix in 80 proof ethanol helps cool the burning fuel, reducing the formation of polluting nitrogen oxides. In general, the hotter the temperature in a cylinder, the more the usually inert nitrogen in air is converted into nitrogen oxides.

The Budd Company's Different Drum

COMPOSITES combine the properties of two or more materials to accomplish tasks beyond the capabilities of homogeneous substances. An early example was the addition of straw to bricks to resist breakage. Currently, carbon-reinforced plastics produce lighter, stiffer golf clubs and tennis rackets, and designers are looking at exotic metal-ferro-aramic combinations for high performance aerospace applications.

Closer to earth, the Budd Company has used two traditional materials, steel and cast iron, to produce a new truck-brake drum. The company, which is based in Troy, Mich., expects the new drum to last 30 percent longer than conventional cast-iron drums.

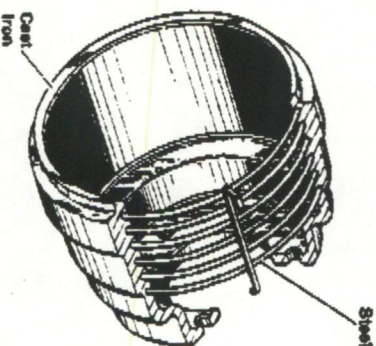
When brakes are applied, the force of the pads on the drum acts to expand it, forming tiny cracks, called checks, in the braking surface. Over time, the checks grow into larger cracks that spread through the drum, causing it to fail.

The composite drum has a cage of steel wires inside the iron casting. Since the steel is stiffer than iron, it absorbs most of the force of braking, reducing cracking. But the iron matrix enveloping the steel absorbs and dissipates most of the heat of braking, retaining that material's

advantage.

Budd engineers say the current composite brake drum, which is intended for the largest over-the-road trucks, weighs about the same as preceding homogeneous models. But subsequent designs will probably grow lighter as the strength of the steel's reinforcement permits thinner castings.

JOHN HOLUSHA



ALTHOUGH the system has not yet reached the required 0.1 gram level, tests on older engines have shown the ability to cut carbon particulate emissions by more than 50 percent. "The engines we have been testing are 1980-81 vintage, and they meet 1989 standards," Mr. Dobbervin said. "Engines being made today put out about 0.2 grams. Our system will bring it below 0.1."

The tests on the older engines were conducted by Southwest Research Institute, an independent testing organization based in San Antonio. One engine averaged 0.19 grams of particulates in the unmodified state; the emissions were reduced to 0.45 grams with the addition of the Midwest Power system.

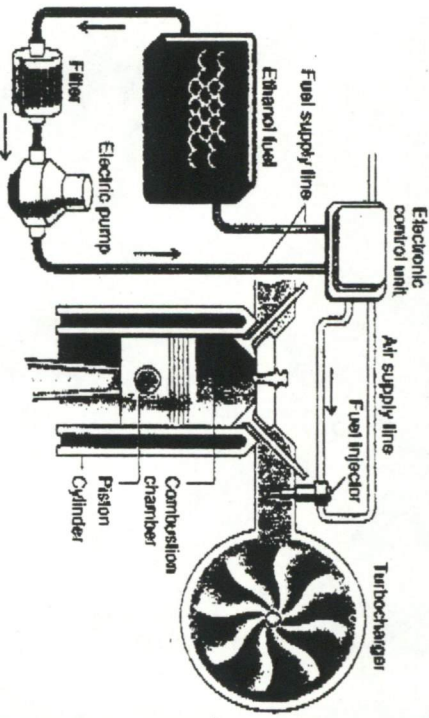
A spokesman for Detroit Diesel Corporation, the leading producer of the two-cycle diesel engines for transit buses, said the tests indicate Midwest Power's system "may have some validity in concept." Nevertheless, the company plans to rely on a methanol-fueled engine to meet the 1991 standards.

A bigger booster of the Midwest Power approach is Stephen Spade, general manager of the Metropolitan Transit Authority in Des Moines, which operated 17 modified buses for three months last year to monitor changes in fuel efficiency and durability. The result was an almost identical fuel cost per mile of 24.60 cents with the modified system, compared to 24.43 cents for straight diesel. Although the modified buses got 0.19 fewer miles per gallon, the lower price of ethanol — 56 cents a gallon compared to 68 cents a gallon for diesel — more than offset the mileage loss.

"I think they are on to something," Mr. Spade said, referring to Mr. Dobbervin and Dwagney Fossen, the actual developer of the system. "I'm normally a skeptic about this sort of thing, but it seems to work," Mr.

Diesel Emission Control System

Low proof ethanol alcohol is injected into the engine which reduces the amount of diesel fuel consumed. The use of ethanol with diesel fuel reduces the amount of soot released with the exhaust during heavy acceleration.



The New York Times, 1/16/89, p. 1, col. 1, 1/16/89

Tough new emissions standards may create a niche for an Iowa energy entrepreneur.

Spade said a test of longer duration involving more modern engines and more vehicles is needed to refine the data on fuel economy and operating costs.

The system, which costs \$2,000 installed, consists of a control box, a separate ethanol fuel tank and pump, a device to inject the alcohol into the engine's incoming airstream and related plumbing and exhaust treatment devices. The ethanol mixture is 45 percent pure ethyl alcohol, 55 percent water, and 5 percent polyglycol oil, a lubricating agent.

According to Mr. Dobbervin, the added control box intercepts the signal from the accelerator pedal before it reaches the manufacturer's control and reduces the demand for diesel fuel by up to 30 percent. Then it activates the alcohol system to start pumping the fuel into the engine's incoming airstream, the intake manifold between the turbocharger and many diesel engines to improve acceleration and the cylinders.

The alcohol enters the cylinder with the incoming airstream, while the diesel fuel is injected by standard means. The only time the diesel fuel and ethanol mix is in the combustion chamber, so the approach is self-fertile from the gas-diesel experiments with

cars, where the two fuels were premixed and pumped into the same tank.

Reducing the diesel fuel flow prevents flooding the cylinders with more fuel than can be burned completely. But just cutting back the diesel fuel flow would make the vehicles unacceptably sluggish in pickup. So the clean burning alcohol is substituted, adding energy and slowing the burning process to hold down the formation of nitrogen oxides. After the bus gets up to speed and the acceleration signal is reduced, the proportion of diesel-to-alcohol is increased.

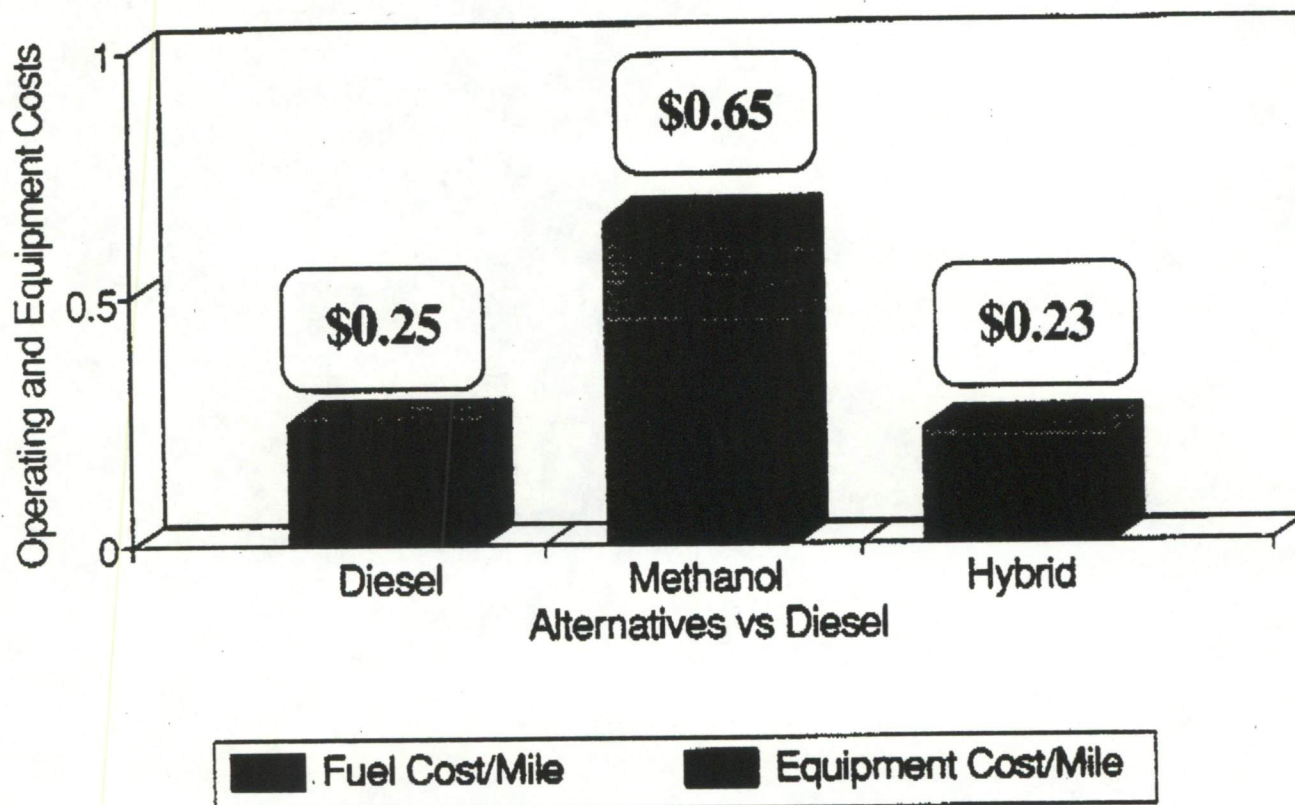
Mr. Dobbervin said the size of the ethanol tank is about 30 percent of the size of the existing diesel tank, so the two containers should enjoy at about the same rate. But if the alcohol tank should empty first, a limp-home mode has been provided for diesel-only operation.

Since transit buses represent only about 2 percent of heavy-duty diesel engines in operation, the 1991 rules represent a large-scale test. In 1993 they are scheduled to cover all heavy-duty diesels, which power the trucks that deliver most of the nation's goods.

BECAUSE it will be many years, if ever, before a nationwide system for distributing alternate fuels is in place, many manufacturers are relying on particulate traps on diesel-fueled engines to meet the emission standards. The traps collect the carbon particles and periodically heat up to burn off the particles.

But Mr. Dobbervin is betting that alcohol injection can compete with traps. "We're working with two large fleets to develop a test program," he said. "If we can demonstrate real-world savings, the lawmakers in Washington will have to take a look."

Cost Comparison Estimated per Mile

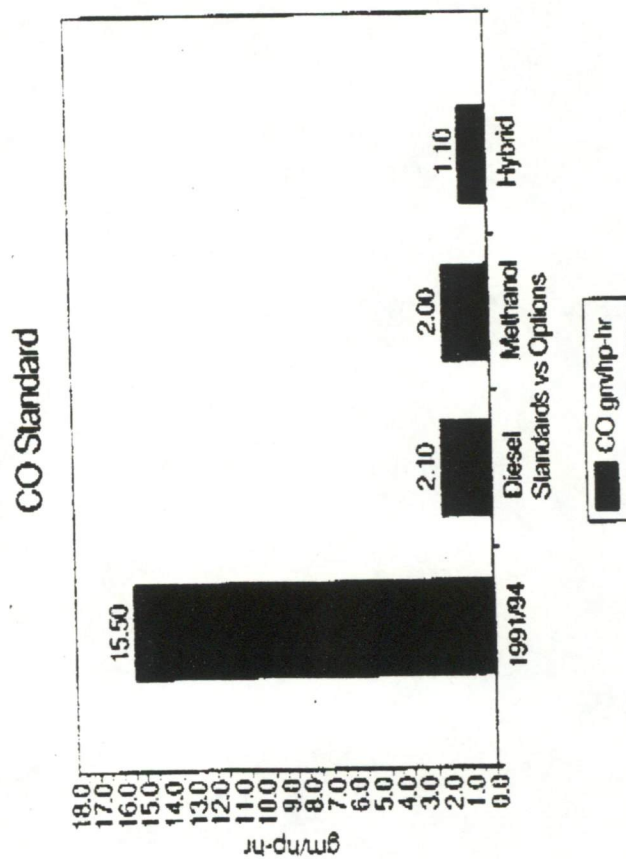
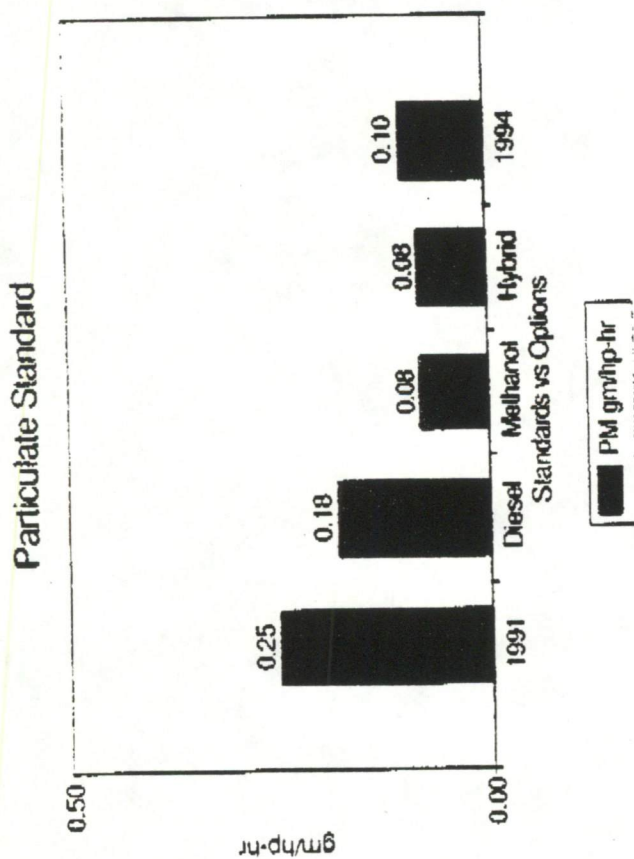
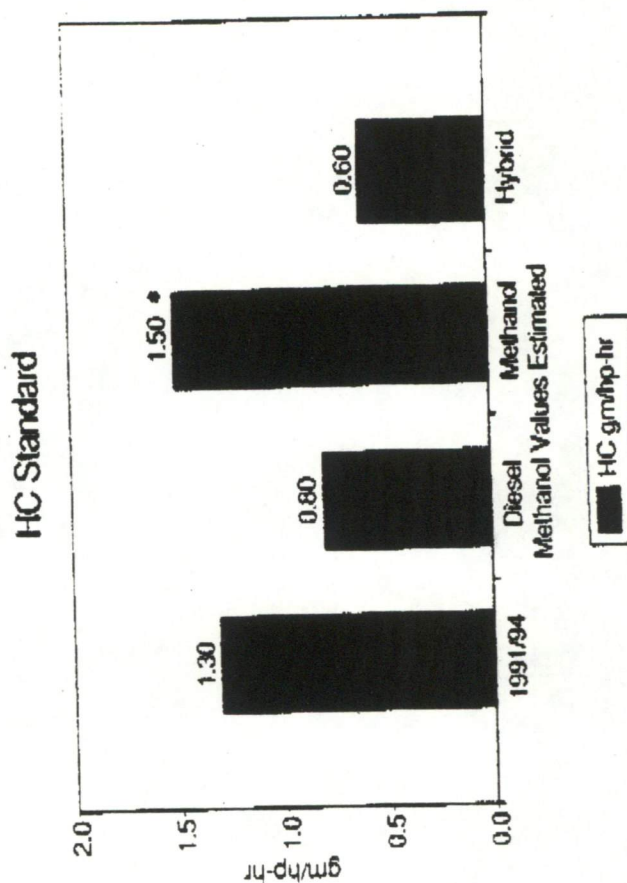
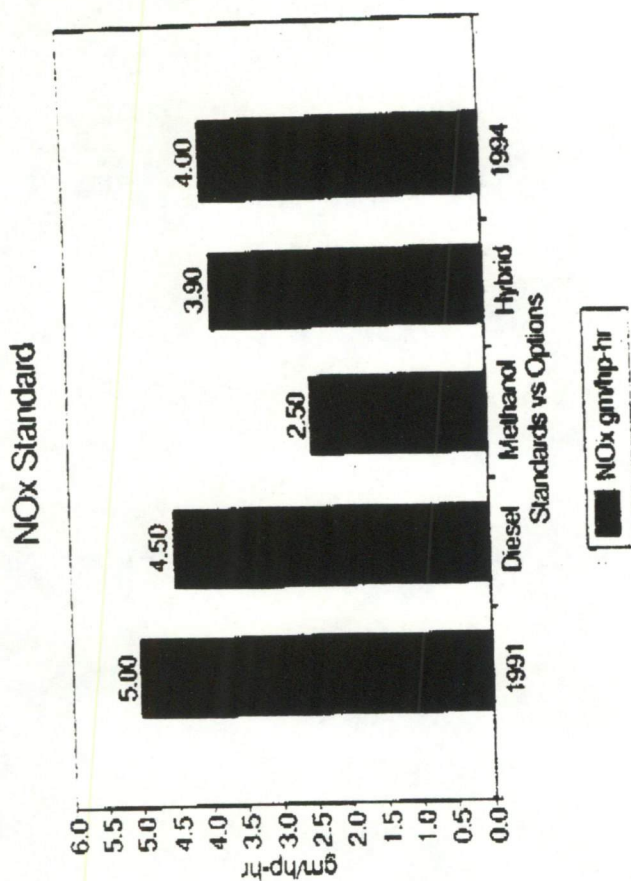


Data for methanol emissions were provided by the American Public Transit Association. Data for the Hybrid system (diesel/ethanol) are actual transient test results conducted during four separate time frames using four different engines at an EPA certified independent test facility.

Assumptions: Diesel fuel \$.88/gallon
Methanol \$.68/gallon
Ethanol (80 proof) \$.58/gallon

Hybrid system uses 80% diesel and 20% low proof ethanol on average throughout the drive cycle. Methanol equipment cost differential for bus retrofit is estimated to be \$20,000. Ethanol/diesel equipment cost differential for bus retrofit is \$7,000. Equipment cost is spread over 100,000 miles of operation for the methanol engines (there is no known engine life warrantee for the methanol engine) and 300,000 for the diesel/ethanol hybrid engines (there is an existing 300,000 mile warrantee for these engines)

Alternative Fuels Comparison



*Detroit Diesel reported on 3/1/90 that their latest runs show 1.1 HC gm/hp-hr without catalyst

Markets

American Exchange, 6
Over-the-Counter, 7
New York Stocks, 8

Sunday World-Herald

OMAHA, NEBRASKA, FEB. 25, 1990
SECTION M—10 PAGES

15 Million Gallons of Grain-Based Fuel

ETBE Plant Planned Along Missouri

By Steve Jordan

World-Herald Staff Writer

Sometime next year, a fleet of cars or trucks may be traveling America's highways powered by a new fuel made partly from grain.

The fuel would come from a new plant to be built along the Missouri River and financed by private companies and Nebraska grain farmers. It would produce 15 million gallons a year of the fuel component, which is blended with gasoline.

The \$5.5 million project would be the largest plant to produce ethyl tertiary butyl ether, or ETBE, a component whose backers say can enhance octane, reduce pollution and cut U.S. oil imports.

2.5 Million Bushels

"The new plant will be the first scale-up of ETBE to commercial use," said Todd Sneller, adviser to the Nebraska Ethanol Authority and Development Board.

Every gallon of ETBE is 42 percent ethanol, an alcohol made from grain. A bushel of corn can yield about 2½ gallons of ethanol.

The proposed commercial plant would consume about 2.5 million bushels of corn to manufacture the 15 million gallons of ETBE. That's about three-tenths of 1 percent of Nebraska's 850-million-bushel yearly corn crop.

Some companies may use fuel from the new plant for fleet testing in vehicles, he said.

American Eagle Fuels, a division of BioCom USA of Atlanta, Ga., has filed its plans for the new plant with the board, a state agency that holds \$18.1 million contributed by grain farmers.

The plant would take about \$3 million of the fund, Sneller said.

The board is to review the plan and give its ruling by April, he said. The board rejected four other proposed sites and is negotiating with owners of

two existing industrial plants in Nebraska within a mile of the Missouri River.

The sites, one about 10 miles south of Omaha and the other about 25 miles south of the city, were chosen because they have access to rail spurs, steam, waste water treatment, water-cooling facilities and a supply of natural gas, he said.

Partners

The new plant could start operations in the late fall and be in production by the last quarter of this year, Sneller said.

One of the industrial property owners is evaluating whether to invest in the ETBE plant, he said. An engineering firm, Foster Wheeler Management Operations Ltd. of Houston, Texas, also may become part owner. And a refining company that will supply some of the isobutylene source also may join the project.

The ethanol authority owns 40 percent of American Eagle, and American Eagle would own 40 percent of the new ETBE plant, Sneller said.

The plant will mark ETBE's move from the laboratory to the marketplace. About a year ago, laboratories were buying ETBE from American Eagle's pilot plant near Lincoln a few liters at a time at a price of about \$350 per gallon.

American Eagle's most recent sale of ETBE was to General Motors Corp. — 45 gallons at \$26 per gallon.

The ethanol authority has pre-sold about half the first year's production of the planned new plant at \$3 per gallon, based on daily production of 1,000 barrels, 42 gallons each.

Sneller said all or most of the first year's production will be sold before the plant opens. The more ETBE the plant produces, the lower the price will drop.

By the second year, he said, ETBE may cost \$1.40 a gallon, comparable to existing gasoline components.

The plant would bring in enough cash to pay for itself in about three years, Sneller said.

Nebraska-Born Fuel Aims to Cut Pollution

By Julie Anderson

WORLD-HERALD BUREAU

Lincoln — A Nebraska-born fuel additive made partly from grain shows promise as a weapon in the fight to reduce vehicle emissions.

The fuel, ETBE, "has a positive contribution to pollution control," said its developer, William Scheller of Lincoln.

Tests in the labs of automobile manufacturers and oil refiners indicate that ETBE has advantages over other octane-enhancing fuel additives in reducing emissions, Scheller said.

Cities, automakers and oil refiners who use and produce such fuels are seeking ways to reduce pollution in the face of forthcoming stricter limits on emissions.

Scheller, a University of Nebraska-Lincoln chemical engineering professor, developed the process to make ETBE. He now is president and chief executive officer of American Eagle Fuels, which operates the nation's only ETBE production plant. The pilot plant produces 10 gallons an hour.

Natural Gas

American Eagle is owned by BioCom USA of Atlanta, Ga., and the Nebraska Ethanol Authority and Development Board.

Scheller said the firm is working on a deal to build a \$5.5 million commercial ETBE plant south of Omaha that would produce 15 million gallons of ETBE a year.

ETBE, ethyl tertiary butyl ether, is made from grain-derived ethanol and isobutylene, a compound derived from oil refining.

ETBE will complement ethanol and compete with MTBE, a fuel additive derived from methanol, to capture a share of the growing market for oxygenated fuels, said Todd Sneller, the ethanol board's adviser in Lincoln.

Ethanol, the alcohol blended with gasoline to make Gasohol, has been shown to reduce emissions of carbon dioxide and nitrogen oxides.

MTBE has carved a niche in the market in the past five years. Sneller said 15 percent of the nation's gas now contains 5 percent to 8 percent MTBE.

Domestic Needs

Because the methanol used to make MTBE is made from natural gas, MTBE has the oil industry's backing, Sneller said.

A disadvantage of MTBE, he said, is that the United States must import methanol to meet its domestic needs.

Researchers testing ETBE have noted other advantages, Scheller said.

ETBE now is one of 27 alternate fuels under study in a \$12 million to \$15



Donna Gray/World-Herald

Tougher pollution standards give ETBE advantages... Some are proposing a 22 percent mixture to further reduce emissions.

million joint research program sponsored by General Motors, Ford, Chrysler and 14 oil companies, said Don Matting, a GM spokesman.

A GM scientist working on the project said ETBE shows promise but has a high production cost.

Scheller said subsidies may help ETBE get into the market.

Treasury Secretary Nicholas Brady sent a copy of a letter to the ethanol board last week indicating that a ruling will be issued soon extending a federal blender's tax credit to ETBE.

The blender's credit gives a share of a federal excise tax incentive to those who make qualified blends of ethanol

Please turn to Page 2, Col. 1.

2-M

SUNDAY WORLD-HERALD February 25, 1990 ***

ETBE Promises Less Pollution

• Continued from Page 1

fuels. So far, the incentive applies only to fuels containing 10 percent ethanol.

Sneller said ETBE backers say the fuel additive should qualify for the blender credit because ETBE is derived from ethanol.

Rep. Richard Durbin, D-Ill., recently proposed extending the tax incentive, including the blender's credit, until 2002.

The tax incentive, set at 6 cents a gallon for the 10 percent ethanol blend, will otherwise expire Sept. 30, 1993. The blender's credit expires at the end of 1992.

Trade Imbalance

Sneller said the extension is necessary to fuel investment in ETBE and ethanol development.

Some people argue against ETBE and ethanol subsidies because corn falls under farm subsidy programs. Sneller said investing in a renewable, native resource would give the nation energy security and reduce trade imbalances.

He said natural gas, according to a 1984 study by the Center for Renewable Resources, received \$4.61 billion in subsidies each year for drilling programs and other credits.

ETBE can help refineries and auto manufacturers solve auto emissions problems in the face of tougher standards, Scheller said.

He said ETBE outranks ethanol and MTBE as an octane enhancer for gasoline.

Octane rating measures how fast a gasoline blend burns. Higher octane gasolines burn faster in the engine and are less likely to cause engine knock.

The knocks, caused when fuel ignites in the engine at the wrong time, indicate the engine is operating inefficiently. A knocking engine emits more carbon monoxide and nitrogen oxides.

An engine's octane requirement is determined in part by its compression ratio, or the extent to which air and fuel are compressed in the engine, Scheller said.

112 Octane

The higher the compression ratio, he said, the higher the octane requirement. Engines with higher compression ratios also are more efficient. However, an increased compression ratio also means higher nitrogen oxide emissions.

ETBE can help in two ways, Scheller said. Gasoline at the pumps today has a minimum octane rating of 87, with more expensive gas blends having higher ratings.

By adding ETBE, with an octane rating of 112, refiners can produce a gas

UNL Cattle to Eat Wet Grain Left from Ethanol Production

About 320 cattle will be assisting a University of Nebraska-Lincoln animal scientist in a two-year study looking at a way to maximize the economics of ethanol production.

Researcher Terry Klopfenstein received \$96,000 from the Nebraska Ethanol Authority and Development Board to study the potential benefits of feeding wet grain left over from ethanol production to feedlot cattle.

Ethanol is produced by fermenting corn. The process consumes the starch in the corn but leaves behind proteins and a nutrient-enriched water. Typically, the water is dumped and the leftover grains dried for sale as cattle feed.

Drying the grain requires energy, and the cost reduces the economic efficiency of ethanol production, Klopfenstein said.

For the study, American Eagle

Fuels' ethanol plant will be moved to Mead, Neb., adjacent to UNL feedlots. Klopfenstein said a similar commercial feedlot-ethanol plant is operating at Garden City, Kan.

The cattle will be fed both the wet grains and the enriched water. About 80 cattle will be involved in the program at a time.

The cattle will be raised for sale as fat cattle, Klopfenstein said. The researchers will study how to make the best use of the feed as a protein and energy source for cattle, with different groups of cattle eating differing amounts of the wet grains.

"We're confident the cattle will perform well," he said.

Klopfenstein said he will calculate the economics of different feeding strategies and attempt to determine the number of cattle an ethanol plant could support.

ETBE contains oxygen and therefore reduces nitrogen oxide emissions.

He said ETBE also is less likely to turn into a vapor than ethanol or MTBE, meaning gasoline blended with ETBE is less likely to escape from gas tanks and become part of the air's load of unburned hydrocarbons.

The Environmental Protection Agency sets volatility standards for fuel high enough so engines will start and run properly, but not so high that too much gas vaporizes from tanks.

Refiners regulate gasoline's vapor pressure by varying the amount of butane they add at the refinery, Scheller said. Butane is produced when gasoline is made from oil.

The EPA has lowered volatility standards to cut hydrocarbons in the atmosphere.

Catalyst

"To the refiner this basically means he can't put as much butane in the gasoline, and all of a sudden he has a surplus of butane in his refinery," Scheller said.

Making ETBE would help reduce this surplus. Butane is a source of isobutylene, one of the components of ETBE, Scheller said.

ETBE is made when ethanol and isobutylene react chemically with the help of a catalyst and heat when run through a bed of solid particles.

ETBE then is blended with gasoline,

which reduces its vapor pressure. The refiner can then add more butane to adjust the vapor pressure.

MTBE and ethanol both raise vapor pressure and do nothing to reduce butane surpluses, he said.

All three of the fuels can replace benzene in gasoline, Scheller said. Benzene has a high octane rating but must be removed or limited in gasoline because it is a known cancer-causing agent.

Scheller predicted that ETBE eventually will be made at refineries and added to gasoline for shipment through gas pipelines.

ETBE has pipeline shipping advantages because it doesn't separate from gasoline like ethanol and doesn't harm pipeline and engine components as does MTBE, Scheller said.

THE WHITE HOUSE

WASHINGTON

March 16, 1990

MEMORANDUM FOR THE FILE

FROM: JEFFREY R. HOLMSTEAD *JRH*
ASSISTANT COUNSEL TO THE PRESIDENT

SUBJECT: Clean Alternative Fuels Program for S. 1630

I have reviewed the above-referenced document, which will be used in on-going discussions regarding the President's proposed amendments to the Clean Air Act. No further action is necessary.

WHITE HOUSE CORRESPONDENCE TRACKING WORKSHEET

☐ O - OUTGOING☐ H - INTERNAL☐ I - INCOMINGDate Correspondence
Received (YY/MM/DD) 1/1Name of Correspondent: Tom Cackette☐ MI Mail Report

User Codes: (A) _____ (B) _____ (C) _____

Subject: Chair Alternative Fuels Programfor S. 1630

ROUTE TO:

ACTION

DISPOSITION

Office/Agency (Staff Name)	Action Code	Tracking Date YY/MM/DD	Type of Response	Code	Completion Date YY/MM/DD
<u>Curtis</u>	ORIGINATOR	<u>9010/1/05</u>			<u>1/1</u>
<u>Curtis 17</u>	Referral Note:	<u>A 9010/1/05</u>		<u>3</u>	<u>9010/1/05</u>
<u>Curtis 02</u>	Referral Note:	<u>I</u>	<u>1/1</u>		<u>1/1</u>
<u>Curtis</u>	Referral Note:	<u>I</u>	<u>1/1</u>		<u>1/1</u>
	Referral Note:		<u>1/1</u>		<u>1/1</u>
	Referral Note:				

ACTION CODES:

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to be used as Enclosure

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X - Interim Reply

DISPOSITION CODES:

A - Answered
B - Non-Special Referral
C - Completed
S - Suspended

FOR OUTGOING CORRESPONDENCE:

Type of Response = Initials of Signer
Code = "A"
Completion Date = Date of Outgoing

Comments: _____

Keep this worksheet attached to the original incoming letter.

Send all routing updates to Central Reference (Room 75, OEOb).

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Refer questions about the correspondence tracking system to Central Reference, ext. 2590.

CLEAN ALTERNATIVE FUELS PROGRAM FOR S.1630

Recommendations of the State of California, as represented by the
California Air Resources Board, Energy Commission and South Coast
Air Quality Management District
(1/3/90, rev.)

Summary: Beginning with model year 1994, low emission, clean fueled vehicles would be introduced in substantial numbers in California, which has the nation's only "extreme" non-attainment area for ozone, greater Los Angeles. The air quality plan for Los Angeles has demonstrated that use of clean fuel vehicles is necessary if attainment is to be achieved within 20 years, as required by S.1630. This early introduction in California would provide a real life demonstration of the public acceptance and on-road emission performance of clean fuel vehicles.

Introduction of clean fueled vehicles in the severe and larger serious non-attainment areas would begin three years later. Smaller serious areas could opt-in if the need is demonstrated. These determinations, made through the SIP process, would also identify how many clean fueled vehicles would be needed in each area. Based on this determination, vehicle manufacturers and fuel suppliers would know in advance the demand for clean vehicles and fuels.

The term "clean fueled vehicle" would be defined as any vehicle whose total reactive organic emissions form at least 50 percent less ozone, and are 50 percent less toxic, than the emissions of similar vehicles meeting the conventional vehicle standards applicable in that model year. This emission reduction requirement would be increased by the EPA as low emission technology advances. The vehicle's emission performance would determine which of the many combinations of emission control technology and cleaner fuels would qualify a vehicle as clean fueled.

Program details can be found on the next page.

-2-

Scope: Introduction of clean fueled vehicles in greater Los Angeles would begin in model year 1994, and expands in 1997 to those severe non-attainment areas and serious non-attainment areas with over 300,000 population which demonstrate the need for clean fuel vehicles through the State Implementation Planning (SIP) process. This program would complement the two tier emission standards in S.1630.

Production of Clean Fueled Vehicles: EPA shall require vehicle manufacturers to produce and offer for sale the following number of light and medium duty clean fueled vehicles:

1994	150,000
1995	300,000
1996	400,000
1997+	as determined by SIPs for extreme, severe and larger serious ozone nonattainment areas

In 1994-96, the number of clean fueled vehicles referenced above shall be offered for sale in California. To determine how many vehicles would need to be produced in 1997 and subsequent years, states with severe ozone non-attainment areas would be required to determine through the SIP process how many clean fueled vehicles are needed to attain air quality standards within the time period (10 or 15 years) provided in the Act, subject to a minimum of 30 percent of new vehicle sales. Areas may opt-out if it is shown that the use of clean-fueled vehicles would not contribute to improved air quality. Areas with less severe air pollution could opt-in based on a showing that clean fueled vehicles are needed to reach attainment. Based on these evaluations, EPA would notify vehicle manufacturers of how many clean fuel vehicles would need to be produced for each state. EPA would be required to provide the necessary methodology and criteria by 1992 on which the SIP evaluations would be made. The EPA methodology shall address the regional and local impacts of clean fuel use, including the need for areas upwind of nonattainment to use clean fueled vehicles, and shall be compatible with modeling and other techniques used in the SIP process.

Fleets: Each severe and extreme area shall, beginning in 1994, require operators of fleets of 10 or greater vehicles to purchase clean fuel vehicles, subject during 1994 to 1996 to the availability of appropriate models. States may require fleets

-3-

capable of being centrally fueled to purchase dedicated fuel vehicles. Vehicle manufacturers providing clean fuel vehicles for sale in California in 1994 would be required to make clean fuel vehicles available in the rest of the nation in numbers sufficient to sustain the fleet programs in affected areas. Each vehicle manufacturer who has sold greater than 100,000 vehicles in the U.S. in any single year would be required to certify and make available for sale at least one dedicated clean fuel vehicle by 1994. Each heavy duty engine manufacturer would be required to certify and make available for sale one engine model beginning in 1997 if the need for such engines are demonstrated in the SIP process.

Emission Standards: Clean fueled vehicles must be certified to have reactive organic emissions which form at least 50% less ozone and are 50% less toxic than the emissions of similar vehicles meeting the conventional vehicle standards applicable in that model year. This percentage emission reduction requirement could be increased as more effective emission controls and improved fuels are developed. Clean fueled vehicles must meet all other applicable emission standards. Vehicles which emit aldehydes would have to meet emission standards for this pollutant which are at least as stringent as those that have been adopted by California. A provision would be included to assure that vehicle fuel cycle causes of greenhouse gases would not exceed those for the conventional gasoline fuel cycle. Urban transit districts would be required to convert existing buses, at the time of major overhaul, to meet the 1991 emission standards.

Fuel Supply: Fuel suppliers would be required to make available and sell sufficient clean fuels at larger service stations and on major transportation corridors to meet the fueling needs of the clean fuel vehicles in operation.

Level Playing Field: Vehicle emissions, not fuel type, would determine whether a vehicle qualifies as a clean fuel vehicle. For example, a vehicle manufacturer may choose to use very advanced emission controls with conventional gasoline, conventional emission controls with very clean fuel, or a combination of moderately improved controls and fuel. Whichever approach is chosen by the manufacturer, the resulting reactive organic emissions would have to form at least 50 percent less ozone and be 50 percent less toxic than the emissions of a vehicle which otherwise meets conventional emission standards for that model year. The process of choosing which approach or

-4-

approaches complies with the more stringent clean fuel vehicle emission standards will determine the fuels that will need to be made available by the fuel suppliers. This will be known several years in advance of the sale of vehicles, thus providing the fuel suppliers with leadtime to make the necessary fuels available.

Marketable Credits: Beginning in 1997 marketable credits could be generated by producing more vehicles or selling more fuels than required. This could benefit smaller companies who may find it more economical to buy credits than invest in the distribution and sale of a new fuel.

Marketable credits could also be generated by converting new or used gasoline vehicles to meet clean fueled vehicle standards. For example, electric motors and batteries could be installed in van chassis. Existing gasoline vehicles could be converted to operate on natural gas. EPA would be required to adopt procedures governing the conversion of vehicles to assure that emission control performance is not compromised. The resulting credits could be sold to vehicle manufacturers to reduce their requirements to produce clean fueled vehicles.

The marketable credits system will help producers of non-liquid fuels (e.g. natural gas and electricity) compete in the traditional liquid fuel marketplace.

Draft

Comparison of CA to Chaffee2 Clean Fuels Proposal

	<u>CA</u>	<u>Chaffee2</u>
<u>SCOPE</u>	Extreme, severe & larger serious areas; possible opt-out; LDVs, some heavy duty	Extreme & severe areas; may opt-in; possible to opt-out, opt-up to higher sales reqm't; all post-2000 nonattainment areas are "in".
<u>PHASE-IN</u>	Mandated program in CA beginning in 1994; in other severe and larger serious areas in 1997.	Same
<u>#Clean Fuel Vehicles</u>	Produce and Offer for Sale:	Beginning in 2000; LDVs only produce:
	1994: 150000 in CA, plus fleet needs	1994: 10% LA sales (90,000)
	1995: 300000 in CA, plus fleet needs	1995: 20% LA sales (180,000)
	1996: 400000 in CA, plus fleet needs	1996: 30% LA sales (270,000)
	1997+: as determined by SIP analysis of air quality need, but minimum of 30% of sales in nonattainment area	1997+: 60% LA sales; 10/20/30% (in '97, '98, '99+) in severe areas; 30% in all post-2000 non-attainment areas (beginning in 2000)
		1994+: Certify one "ultra-clean" vehicle, (ultra-clean vehicle counts as 3 clean fueled vehicles)
<u>CLEAN FUEL FLEETS</u>	Beginning in 1994, all fleets (10 or more vehicles) in extreme & severe areas must purchase clean fuel vehicles, subject to vehicle availability, during 1994-96; 1 model per manufacturer must be dedicated clean fuel vehicle; 1 heavy duty engine per manufacturer if states indicate need; buses retrofitted to meet 1991 standards.	30% of new fleet sales (fleets of 10 or more vehicles), beginning in 1997 in extreme & severe areas, must be "ultra" clean vehicles, count towards production reqm'ts.

-2-

EMISSION
STANDARDS

50% less ozone-forming potential,
50% less toxic than standard
applicable to conventional
vehicles in that year. EPA
may increase % reduction
requirement if new technology
develops. Formaldehyde
standard at least as
stringent as adopted in CA.
No increase in greenhouse gases.

"Clean Fuel" vehicles have a
total vehicle reactive
organics of 0.6 gpm or less
(presumable reactivity
adjusted for low reactivity
fuels???), 40% lower toxic
emissions compared to 1993
model. "Ultra clean"
vehicles have organics of
0.2 gpm or less and 90%
lower toxic emissions
Formaldehyde standard no
higher than 0.015 gpm.
No increase in greenhouse
gases.

RELATIONSHIP TO
"SECOND TIER"
STANDARDS

Clean fuel vehicles always
twice as clean as current
conventional emission std.
including second tier
(0.125 THC) standards

All cars meet second
tier standards in 2003

FUEL
SUPPLY

Fuel suppliers must sell
sufficient clean fuels at
larger stations and on
major transportation
corridors to meet needs of
clean fuel vehicles in
operation.

Fuel suppliers must sell
requisite type & amount
of fuel. Fuels must be
available at larger stations.
EPA may extend availability
requirement to transportation
corridors.

LEVEL PLAYING
FIELD

Fuel Neutral

Fuel Neutral

MARKETABLE
CREDITS

Available for producing
extra vehicles or selling
extra fuel; also available
for converting new or
existing vehicles to operate
on clean fuels. EPA must
adopt requirements
governing conversions.

Program to include market-
able credits for auto
manufacturers, fuel suppliers
& fleet operators

STUDIES

EPA to provide methodology
to be used by states to
determine how many clean
fuel vehicles are needed.

EPA fleet demonstration
(through 1995), emission
testing, air quality
modeling required. Reports
to Congress in 1992/95.



Clean Air -
Jeff
Alternative Fuels

Advanced Engineering Staff

November 27, 1989

Mr. James F. Olmsted
4620 North 26th Street
Arlington, VA 22207

Ref: N.D. File #224929 D

Dear Mr. Olmsted:

Thank you for the many letters and informational attachments of the past few months. We are also in receipt of a May 18, 1989 letter from Mr. Robert B. Evans to Mr. Ronald H. Haas, Vice President, Current Engineering & Manufacturing Services Staff, General Motors Corporation. In an attachment to that letter a summary of data is listed under the caption "Bank of America" and dated July 15, 1983 that indicates substantial benefits in exhaust emissions and fuel economy with the Webster Heise valve in a methanol fueled Citation.

We would be interested in reviewing the conditions of the tests yielding the reported benefits and possibly in ourselves testing the subject vehicle. However, since this data goes back a way in time, it may be better to evaluate an updated system of yours in a contemporary vehicle.

General Motors concentrated effort on methanol vehicles is currently based on the 3.1 liter Lumina and 2.8 liter Corsica vehicles. Our interest, therefore, would be in any improvement your device would offer in these vehicles. If you would care to have your device evaluated, we would be prepared to furnish a vehicle to you for revision which we would then test and evaluate.

Thank you again for your continued interest in General Motors and its products. We were sorry to hear of the death of Mr. Sherwood F. Webster and are reassured by your mailings that his ideas will be diligently pursued.

Very truly yours,

Otto A. Ludecke
Director
New Devices Section

vs



Let's Get It Together
Safety Belts Save Lives

JAMES F. OLMSTED
4620 N. 26TH STREET
ARLINGTON, VIRGINIA 22207

December 18, 1989

Re: Webster-Heise Valve #224929

Dear Otto:

Your encouraging letter of November 27th indicates considerable interest in alcohol fuel, which has been the primary focus of Webster-Heise efforts throughout 1989.

The 1983 methanol (M-85) summary you mentioned was prepared by Merle R. Fisher, then Vice-President of Bank of America, now retired in Danville, CA (415)837-8881. I believe John Dobb reviewed the data with Merle, but am enclosing another copy of the dynamometer print-out from which our data was extracted. The vehicle tested in July 1983 is now owned by Boyden Gray, as explained in my letter to you of September 15th, who demonstrated it for GM officials in your Washington office during 1987-8.

Earlier this year Dick Heise installed valves in 1989 Corsicas and achieved improved performance when driving on ethanol (E-85). He has recently done extensive ethanol testing, including FTP dynamometer runs, which he would be happy to discuss with you directly.

At a Board Meeting on November 24th Dick was elected President of Webster-Heise Corporation and operations were subsequently moved to: 4211 E. Elwood Street, Suite 5
Phoenix, Arizona 85040
(602) 437-4707

Best wishes for a cheerful Christmas vacation, after which we look forward to working with you to relieve Joe Calhoun's anguish. (Enclosure)

Sincerely yours,



Mr. Otto A. Ludecke, Director
New Devices
General Motors Corporation
30200 Mound Road
Warren, Michigan 48090

Enclosures

*Boyden - This is your chance to unload
the car on GM at a profit*

California Steps Up Anti-Pollution Drive

By ROBERT REINHOLD

Special to The New York Times

LOS ANGELES, Dec. 15 — In its quest to clean up polluted air over Los Angeles and other major cities, California is putting unparalleled pressure on automobile makers and fuel companies to cooperate in designing the low-polluting vehicles of the future.

The State Air Resources Board is considering a stringent plan that would require the phasing in of increasingly low-emission vehicles by the year 1994 until all cars sold in the state meet drastic new clean-air standards by 2000.

This is expected to require a major shift to cleaner fuels like natural gas, methanol and electricity. Service stations would be compelled to sell such fuels, along with gasoline.

The board gave general endorsement to the plan Thursday evening here, though no final action is due until September pending consultations with the petroleum industry, Detroit automobile makers and electric utilities.

Cooperation is needed now because the proposed new standards are so strict that no industry can meet them alone. Under Federal law, California is permitted to establish its own automobile emissions standards, whereas less stringent Environmental Protection Agency rules prevail elsewhere.

Total Package Is Sought

"We have always regulated the automobile and fuel industries separately," Bill Sessa, spokesman for the board, said today. "But now the auto and oil industries are going to have to cooperate to an uncommon degree. We are really looking at the total package of both car and fuel to meet these goals."

By focusing on auto emissions, the proposal supplements a recently adopted smog control plan for the Los Angeles basin. Though this is a state initiative, it is expected to have broad national impact. California's emission standards, stricter than those required by the Federal Government, have been adopted by many other states, including New York. In addition, California represents 10 percent of the national car market.

Coming just months after the state cut allowable emissions by 30 to 50 percent for 1993-1997 model cars, the proposal has struck the automobile industry as unrealistic.

"We are aware of the air pollution problem in California, but the standards they have proposed are not feasi-

ble in the time frame," said Joseph C. Calhoun, assistant director of auto emissions control for the General Motors Corporation. "We do not think the technology will be available." He urged a slower approach.

Mike Schwarz, manager of emissions control analysis and planning at the Ford Motor Company, said, "These levels are on the order of 50 to 84 percent reductions from levels we haven't yet achieved."

Petroleum Industry Optimistic

But the petroleum industry is more sanguine. Douglas F. Henderson, executive director of the Western States Petroleum Association, which represents 50 refiners and sellers of gasoline in six Western states, called the plan a "watershed event." And Daniel J. Townsend, manager of operations sup-

Unparalleled pressure on car makers and fuel companies.

port for Arco, the largest seller of gasoline in California, said his company "enthusiastically" endorses the broad concept despite reservations about parts of it. "We are confident we can reformulate gasoline that is clean enough for Detroit to meet the emissions standards," he said.

Also enthusiastic are electric utilities, seeing a new market, although Mr. Sessa said gasoline would be the dominant fuel for many years.

The proposal envisions three kinds of new cars, each progressively cleaner.

In the first phase, from 1994 through 1996, up to 10 percent of new cars and light trucks sold would have to emit no more than .125 grams of polluting hydrocarbons per mile, half the current new California standard of .25 grams. About 150,000 such vehicles would be sold each year. For now, proposals would only apply for cars and light trucks. Heavier vehicles like trucks and buses will be dealt with later.

The pressure would mount beginning in 1997, when the hydrocarbon standard would be halved again, to .075 grams. For that year, one of every four cars sold would have to meet that

standard and the proportion would rise to 98 percent in the year 2000.

And beginning in 1995, manufacturers would have to start selling some cars in which the standard is cut by nearly half again, to .04 grams. It is expected most of these cars would require alternative fuels like methanol, natural gas, liquefied petroleum gas and electricity. Fuel suppliers would have to sell clean fuels in proportion to the demand. The board's staff estimated that clean fuels would displace one billion gallons of gasoline in 1997 and 11 billion gallons by 2006.

The board said conventional gasoline could still be used to fuel the second generation of new vehicles, based on tests of electrically heated catalysts to capture pollutants in the tailpipe. But the third-generation cars are expected to require major innovations and fuels like compressed natural gas and electricity, and possibly reformulated gasoline. The three major American car makers and major oil companies recently began a joint effort to develop such vehicles.

But the auto industry is dubious about the California timetable. "We think that in the mid-1990's there can start to be some alternative fuel vehicles," Mr. Schwarz of Ford said. "Whether they can meet these standards is unknown at this point. There's not a rational technical basis for saying the rate of penetration in the fleet they have proposed is feasible."

Mr. Sessa said the air board, on the basis of laboratory prototype engines, was confident the deadlines could be met. The auto industry says prototypes are not reliable indicators because performance tends to deteriorate rapidly with a vehicle's age and road use.

The electric and gas utilities, meanwhile, see new opportunity. While current technology makes gas- and electric-powered vehicles rather impractical, utilities are experimenting. San Francisco-based Pacific Gas and Electric Company, which serves northern and central California, is building the first compressed natural gas service station in Concord, in the East Bay area.

"We see it as an opportunity for PG&E to expand on our existing services," said their spokesman, Ron Rukowski. "Right now we provide natural gas, electricity and energy management. We can take this one step further to provide information about CNG and electric vehicles."

THE WHITE HOUSE
WASHINGTON

November 9, 1989

MEMORANDUM FOR THE FILE

FROM: JEFFREY R. HOLMSTEAD *JRH*
ASSISTANT COUNSEL TO THE PRESIDENT

SUBJECT: News Clip from USA TODAY - Concerning Cars
Running on Alternative Fuels

I have reviewed the above-referenced document, which will be used in on-going discussions regarding the President's proposed amendments to the Clean Air Act. No further action is necessary.

Cleanair.1

2

11/9

make subject

fin copy

Document Originally
Attached to
Following Page

WHITE HOUSE CORRESPONDENCE TRACKING WORKSHEET

☐ O - OUTGOING☐ H - INTERNAL☐ I - INCOMINGDate Correspondence
Received (YY/MM/DD) 1 1 1Name of Correspondent: Bill Rosenberg☐ MI Mail Report

User Codes: (A) _____ (B) _____ (C) _____

Subject: News Clip from USA TODAY with the results
of a survey concerning cars running on
alternative fuels**ROUTE TO:****ACTION****DISPOSITION**

Office/Agency	(Staff Name)	Action Code	Tracking Date YY/MM/DD	Type of Response	Code	Completion Date YY/MM/DD
	<u>Cutler</u>	ORIGINATOR	<u>89.11.08</u>			<u>1 1</u>
	<u>Int 17</u>	Referral Note: <u>A</u>	<u>89.11.08</u>		<u>S</u>	<u>89.11.09</u>
	<u>Int 02</u>	Referral Note: <u>A</u>	<u>1 1</u>			<u>1 1</u>
	<u>Mr. Gray</u>	Referral Note: <u>A</u>	<u>1 1</u>			<u>1 1</u>
		Referral Note:	<u>1 1</u>			<u>1 1</u>
		Referral Note:				

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OAR/IMMEDIATE OFFICE
Facsimile Cover Sheet

TO: Boydew Gray

OFFICE: _____

TELEPHONE: 452 - 2632

DATE: 11/7 NO. OF PAGES: 3

FROM: Bill Rosenberg - EPA
382 - 7400

MESSAGE/INSTRUCTIONS: _____



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

OFFICE OF
AIR AND RADIATION

November 7, 1989

Note to: Boyden Gray
Roger Porter
Nancy Maloley
Bob Grady

Attached is a piece from USA TODAY with the results of a survey showing that:

- o 68% of consumers say carmakers should be required to build cars that run on alternative fuels
- o 46% are willing to pay \$200 or more for such a car

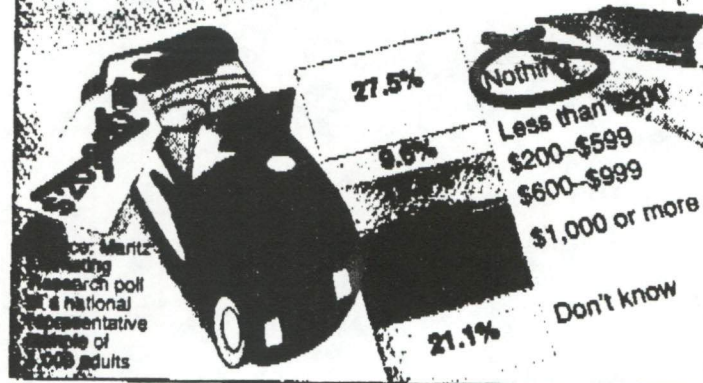
Bill Rosenberg

USA SNAPSHOTS®

A look at statistics that shape your finances

Drivers want fuel choices

68% of consumers say carmakers should be required to build cars that run on alternative fuels. How much more they're willing to pay for such a car:



By Julie Stacey, USA TODAY

WHITE HOUSE CORRESPONDENCE TRACKING WORKSHEET

☒ O - OUTGOING☐ H - INTERNAL☐ I - INCOMINGDate Correspondence
Received (YY/MM/DD) 1/1Name of Correspondent: James Johnston☐ MI Mail Report

User Codes: (A) _____ (B) _____ (C) _____

Subject: Comparison of HR 3030 to Administration Proposal

ROUTE TO:

ACTION

DISPOSITION

Office/Agency. (Staff Name)	Action Code	Tracking Date YY/MM/DD	Type of Response	Code	Completion Date YY/MM/DD
<u>Cuoz</u>	ORIGINATOR	<u>90105109</u>			<u>1/1</u>
<u>Cuat 18</u>	Referral Note: <u>I</u>	<u>90105109</u>		<u>S</u>	<u>90105109</u>
<u>Cuat 17</u>	Referral Note: <u>I</u>	<u>90105109</u>			<u>1/1</u>
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	Referral Note: _____				

ACTION CODES:

A - Appropriate Action
C - Comment/Recommendation
D - Draft Response
F - Furnish Fact Sheet
to be used as Enclosure

I - Info Copy Only/No Action Necessary
R - Direct Reply w/Copy
S - For Signature
X - Interim Reply

DISPOSITION CODES:

A - Answered C - Completed
B - Non-Special Referral S - Suspended

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Type of Response = Initials of Signer
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1/3

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JDX
FROM
JAMES D. JOHNSTON
VICE PRESIDENT
INDUSTRY-GOVERNMENT RELATIONS

5/9/90

TO *Boyd Gray*
The White House

Boyd:

*Here is the analysis you
asked me to fax. As it
shows, the House Committee
bill does the job.*

*I'm glad we are "singing
out of the same hymn" in
opposition to Waxman-Tennis.*

*I'll look forward to your
blue print.*
Jim

SUITE 401
(202) 775-5090
ROOM 13-137
(313) 556-4671

1660 L STREET, N.W.
WASHINGTON, D.C. 20036
GENERAL MOTORS BLDG.
DETROIT, MICHIGAN 48202

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COMPARISON OF HR3030 TO ADMINISTRATION PROPOSAL

With respect to mobile sources (Title II), HR3030 is as stringent as, and goes further than, the original Administration Proposal in a number of ways:

100,000 Mile Standards: The Tier I emissions standards in HR3030 are more restrictive than the emission standards in the Administration Proposal. HR3030 requires manufacturers to certify to emission standards for 10 years or 100,000 miles with in-use testing up to 75,000 miles. Standards beyond 50,000 miles were not included in the Administration Proposal. While the difference is difficult to quantify, the HR3030 standards are expected to affect emissions and air quality in a beneficial direction.

Lower Passenger Car NOx Standard: The HR3030 passenger car NOx standard is 0.4 g/mi, compared to 0.7 g/mi in the original Administration Proposal.

Lower Light Duty Truck Standards: HR3030 requires many lighter trucks to meet the same emission standards as cars. In addition, all intermediate weight light trucks must meet a tighter hydrocarbon standard than the Administration Proposal.

Alternative Fuels Program: HR3030 provides the same basic alternative fuel emission reductions as the original Administration Proposal. The original Administration Proposal would have required a 30% reduction of VOC emissions from a 0.95 gpm car on 30% of the cars (i.e. 9% overall VOC reduction) in severe and extreme areas. HR3030 provides the same VOC reduction by requiring all cars to meet a standard of 0.86 gpm (i.e. 9% reduction from 0.95 gpm baseline vehicle). Likewise, the second phase of the Administration Proposal would have required an 80% reduction from a 0.95 gpm car on 30% of the cars (i.e. 24% overall VOC reduction). HR3030 accomplishes this reduction by requiring all cars to meet a 0.72 gpm requirement (i.e. 24% reduction from 0.95 gpm baseline vehicle). HR3030 contains a fleet program with tough VOC standards of 0.66 and 0.25 g/mi. These standards will likely require dedicated clean-fuel vehicle technologies and will provide VOC reductions beyond the original Administration Proposal.

Reformulated Gasoline: HR3030 requires reformulated gasoline to be made available to older cars in the nine-city area in 1995 which was not included in the original Administration Proposal. This provides important near-term emission reductions on the current in-use vehicle population. The table below shows air quality benefits of the alternative fuels portion of the original Administration Proposal and HR3030 for alternative fuels and reformulated gasoline for several calendar years.

Emission Reduction % - Alternative Fuels, Including Reformulated Gas

Calendar Year	Administration	HR3030
1995	<0.1%	3.0%
2000	0.2%	2.3%
2005	0.9%	2.2%
2010	1.4%	2.3%

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The proposals will provide equal emission reductions when all of the pre-1995 cars and trucks are retired from service.

Tier II Emission Standards: HR3030 adds Sec. 202 (i) which includes a second round (Tier II) of emission standards in 2004 for passenger and light duty trucks up to 3750 lbs. loaded vehicle weight. A second round of more stringent standards was not included in the Administration Proposal. Unless EPA determines that the Tier II standards are not needed or that technology is not available, or unless EPA promulgates alternative standards, the Tier II standards are effective with the 2004 model year.

Comparison of Emission Reduction Impact:

The following table compares the original Administration Proposal and HR3030. The total benefits include Tier II standards. HR3030, with or without Tier II, achieves a greater total emission benefit than the original Administration Proposal.

Mobile Source VOC Emission Reductions in Year 2005*

	Admin. Proposal	HR3030
Base Program	8.6	8.6
RVP I	7.1	7.1
RVP II	8.2	8.2
Evap/Running Loss	3.5	3.5
Tailpipe	0.9	0.9**
Refueling (Stage II)	1.5	1.5
Alternative Fuels	0.9	2.3***
(Severe+Extreme Only)		
	<u>30.7</u>	<u>32.1</u>
Other Reductions:		
Tier II Exhaust	0.0	0.4
	<u>30.7</u>	<u>32.5</u>
Total Mobile Source	30.7	32.5

*Estimated as a percentage reduction from the total 1987 inventory.

**Emission reductions resulting from extending useful life and light truck standard difference not included.

***Reformulated gasoline assumed to result in a 20% VOC benefit for current cars and trucks.

5/2/90